Natural Gas Storage In Ontario

A study prepared for the Ministry of Energy

Ontario

Ministry of Energy

Honourable Vincent G. Kerrio Minister

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NATURAL GAS STORAGE IN ONTARIO

Prepared for the

Ontario Ministry of Energy

By

Monenco Consultants Limited

July 1986

Ontario Ministry of Energy

Vincent G. Kerrio
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EXECUTIVE SUMMARY

The operation of underground natural gas storage reservoirs in Ontario was first carried out in Welland County in 1915. The continuous operation of underground storage did not commence until 1942, when Union Gas (Union) began operating the Dawn 47-49 pool in Lambton County. Currently there are fifteen operating pools in Ontario with a total annual working capacity of 4,146 10^6m^3. This represents approximately 21% of the annual volume of natural gas consumed in Ontario. The filling of these reservoirs takes place generally during the seven months April through October with the removal of the gas during the heating season, November to March. The flexibility exists, however, to add or remove gas in any month or day, depending on the supply available from TransCanada PipeLines (TCPL) and the demand on the system.

The balancing of supply and demand provided by the storage facilities, along with export market flexibility, allows TCPL to operate its supply system at virtually full capacity throughout the year.

In addition to the underground storage operators (Union, Tecumseh Gas Storage and Consumers' Gas Company Ltd.) ICG Utilities (Ontario) Ltd. has operated a liquefied natural gas (LNG) storage facility for over eighteen years near Sudbury. The LNG plant is used to supply short-duration peak volume requirements during the winter, utilizing gas which is delivered by TCPL during the warmer months.

The requirements for additional underground storage capacity will be provided over the medium term by increasing the operating pressure of current reservoirs (delta-pressuring) and developing depleted pinnacle reef gas production reservoirs. Delta-pressuring of existing reservoirs to planned levels will alone provide more than 25%

additional working capacity. Other longer term storage potential exists in aquifer cavities, a storage means which is in use in the U.S. Midwest.

An indication of the benefits derived from the underground storage facilities is developed by analysing transportation system costs which would be incurred if no seasonal storage were available. When these costs are allocated to gas customers the resulting impact on the various elements of the gas industry appears to be greatest on the low load factor, seasonal user of gas. The residential and small commercial customers would see an estimated increase of 12% in the unit cost of gas if the peak day requirements were to be provided entirely by TCPL.

A preliminary analysis of the capability of underground storage to respond to a disruption in western gas supply indicates that all essential gas services could probably be met for at least the period required to repair physical damages.

The discussion of the proposed Consumers' LNG facility concludes that the needle peak shaving function provided by this method of storage will assist in offsetting the reduction in system load factor anticipated by the utility.

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PART 1

INTRODUCTION

In March 1986 the Ontario Ministry of Energy contracted with Monenco to undertake a study of gas storage in Ontario. The terms of reference for the study are included in Appendix I. This report represents a summary of the investigations and analysis of the current status of storage operations, the potential for additional storage and the analysis of the benefits of storage.

The report begins with a discussion of the development of gas storage as the gas industry itself has developed, with major events highlighted. Part 3 outlines the geology of Ontario and surrounding region. This gives an indication of the unique formations which have allowed the development of economical underground storage in Ontario.

Following these two sections is a description of the geology of gas storage and each major type of storage formation. An assessment of the potential for additional storage capacity is made for each.

In Part 5 a general description of the current gas supply and demand situation is given along with a discussion of how seasonal gas storage fits into the overall balance. This provides the background for Part 6 which introduces rate determinations and the actual costs of gas storage which are included in retail rates. Following from this analysis is the development of a hypothetical delivery system which would exist if the current underground storage facilities were not available. This analysis is developed through the cost allocation process to the determination of the impact on retail rates and other elements of the supply system.

In Part 7 an analysis of the capability of the storage system to provide supply to Ontario customers in the event of a major TransCanada interruption is outlined. This is followed by a description of the proposed Consumers' LNG facility and an assessment of the role it will play in the gas supply system.

Finally a summary of the results of the study is presented along with several conclusions which can be drawn from the investigations and analysis.

PART 2

THE DEVELOPMENT OF GAS STORAGE IN ONTARIO

2.1 HISTORIC DEVELOPMENT

The first recorded attempt to store natural gas underground in Canada took place in Welland County, Ontario. In 1915, the Provincial Gas Company successfully transferred natural gas from some high pressure wells into several low pressure wells located in a partially depleted gas field near Welland. The gas, which had been injected during low periods of demand, was removed the following winter during periods of peak demand, demonstrating the potential of this technology for gas storage and distribution(1)(2)(3).

Although the first gas lease agreements regarding exploration, drilling and production were signed in 1927 in Ontario, continuous underground storage of gas did not take place until October of 1942(1)(4). At that time, Union Gas Limited (Union) began storing reformed refinery gas in a pinnacle reef formation, designated as Dawn 47-49 Pool, in Dawn Township, Lambton County. The reformed refinery still gas was being produced by a plant Union had constructed which accepted and reformed waste still gases from the nearby Imperial Oil refinery in Sarnia(4). The following year (1943), a second pool, Dawn 59-85, was put into service for gas storage purposes.

In the mid-1940's, Union Gas Limited and Panhandle Eastern Pipeline Company entered into an agreement in which the latter company agreed to supply Union 5.5 billion cubic feet of natural gas annually for a 20 year period. The import of this gas commenced in 1947. Since this gas was being delivered in the off-peak summer period from April to October, inclusive, and Union's business was temperature sensitive, most of this gas had to be stored(1)(4).

Since Union was taking delivery of most of their natural gas within the off-peak summer period and because of interruptibility and curtailment provisions in their gas purchase contracts, underground

storage played an important role in their operation. For instance, both the 1954 contract with Panhandle Eastern (a second contract) and the 1955 agreement with TransCanada PipeLines had two-thirds of the natural gas being delivered during the off-peak summer period with the remaining third being delivered during the winter period. Both contracts were also interruptible on a daily basis and were 75% take or pay contracts with a one part rate(4).

In 1950, three pools in Lambton County, Dawn 47-49, Dawn 59-85 and Dawn No. 3 were officially designated as gas storage pools even though the first two pools had been in use since 1942 and 1943, respectively. Dawn No. 3, a lenticular pool, although designated in 1950 as a storage pool, was not utilized until 1954(1). Storage operations were later terminated and the lands de-designated.

By 1953, underground storage was used solely for natural gas storage. Manufactured gas and reformed refinery gas were no longer being stored underground(1).

In 1957, a fourth storage pool in Lambton County, the Payne Pool, was officially designated. Injection and storage of natural gas started soon after. In that same year, a pipeline (Union Gas) linking storage areas in Lambton County and the Toronto Trafalgar Lisgar facility was completed(1).

The TransCanada pipeline was completed in 1958 making Alberta natural gas available to central Canada. With the completion of the transport facilities between Lisgar and the Lambton County storage facilities the year before, it was not long after the completion of the TransCanada pipeline that natural gas from Alberta was being injected and stored in Lambton County (1959). In 1958, further use of underground storage was made when Union agreed to store up to 7.5 billion cubic feet annually for Consumers' Gas Company (Consumers') for a 20 year period(1)(2)(4).

To meet increased storage demands, the Waubuno Pool, which had been officially designated for storage in 1955, was put into service in 1960. This brought to five the number of underground storage pools being used by Union in southwestern Ontario.

By 1962, the need for a sixth storage pool had developed and subsequently, Dawn 156 was designated and put into use. Also that year, five storage pools (Kimball-Collinville, Seckerton, Corunna, Sombra and Bickford), in Lambton County, developed by Imperial Oil, were designated as gas storage areas. In Welland County, Consumers' activated the Crowland storage pool (lenticular) for storage(1) in 1982.

In 1963, Tecumseh Gas Storage Limited (Tecumseh) entered the gas storage business when it acquired the storage rights and facilities of three Imperial Oil storage pools: Corunna, Kimball-Collinville and Seckerton. Authority to inject, store and remove natural gas from these facilities was obtained the following year. As well, in 1963, Tecumseh agreed to commence storing gas for Consumers' in 1964. In that same year, the Zone Pool, a lenticular pool located in Kent County was designated as a storage pool(1) but never became operational.

Over the years, storage pools were added as storage requirements dictated. With regard to Union, the Bickford Pool, under a joint venture agreement with Imperial Oil Limited, was acquired and activated for storage in 1972 followed by the Bentpath Pool in 1974, the Terminus and Rosedale Pools in 1975, and finally, Dawn 167 in 1976. All of these pools are located in Lambton County. The only addition to the Tecumseh storage facilities since 1963 has been the Wilkesport Pool which was activated for storage in 1978(5).

2.2 UNION GAS COMPANY LIMITED FACILITIES

Union currently operates ten underground gas storage facilities. All are located in Lambton County with a combined working storage capacity currently of 2,661.300 10^6m^3 (93,946 MMcf). The combined "planned working capacity" of these pools is 3,260.600 10^6m^3 (115,102 MMcf), noting that the "planned capacity" is based on anticipated future cushion pressures and planned maximum operating pressure corresponding to a 15.83 kPa/m (0.70 psi/ft) gradient in the pools(6). A description of each Union storage facility is provided in Table 2-1. The current operating conditions of each reservoir are given in Table 2-2 (metric) and Table 2-3 (Imperial). In addition the Union transportation system is outlined in Figure 2-1.

2.3 TECUMSEH GAS STORAGE LIMITED

Tecumseh, which is owned 50% by Consumers' and 50% by Imperial Oil Limited, operates four underground gas storage facilities, all located in Lambton County. All gas being stored by Tecumseh is for Consumers'. At present, the combined working storage capacity of these pools is 1,472 10^6m^3 (51,992 MMcf) with a combined "planned working capacity" when delta pressured estimated to be 1,985 10^6m^3 (70,111 MMcf). The Tecumseh storage facilities are summarized in Tables 2-4 and 2-5.

Reservoir Name	Bentpath	Bickford	Dawn 47-49	Dawn 59-85	Dawn 156	Dawn 167	Payne	Rosedale	Terminus	Waubuno	
											1.
County	Lambton	Lambton	Lambton	Lambton	Lambton	Lambton	Lambton	Lambton	Lambton	Lambton	2.
Discovery Year	1970	1970	1930	1931	1952	1953	1949	1970	1968	1951	3.
Year Activated for Storage	1974	1972	1962	1943	1962	1976	1957	1975	1975	1960	4.
Storage Formation Name	Guelph	Guelph	Guelph	Guelph	Guelph	Guelph	Guelph	Guelph	Guelph	Guelph	5.
Geologic Age	Silurian	Silurian	Silurian	Silurian	Silurian	Silurian	Silurian	Silurian	Silurian	Silurian	6.
Original Content	Gas	Gas	Gas	Gas	Oil & Gas	Gas	Gas	Gas	Gas	Gas	7.
Average Pay Thickness of Storage Formation (feet)	299	334	254	297	348	194	378	283	303	339	8.
Type of Geologic Trap	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	Bioherm	9.
Maximum Depth (feet)	1,930	2,135	1,855	1,876	1,994	1,724	2,341	1,924	1,898	2,162	10.
Minimum Depth (feet)	1,631	1,801	1,601	1,579	1,646	1,550	1,963	1,641	1,595	1,823	11.
Original Pressure (psig)	867	928	865	865	877	906	877	937	886	931	
Approximate Acreage Reservoir Limits	130	909	187	163	823	360	382	88	215	165	12.
Total	767	2,398	525	450	2,730	1,129	768	457	1,246	514	13.
No. of Output and/or Input Wells	4	4	5	7	11	3	9	1	7	5	
No. of Pressure Control and/or Observation Wells	4	4	2	1	1	2	2	2	1	1	14. 15.
Total Wells	8	8	7	8	12	5	11	3	8	6	16.
No. of Compressor Stations	a	b	c	d	d	e	f	g	h	h	17.
Horsepower of Compressor Stations	—	1,000	70,830	—	—	—	1,140	—	—	—	18.
Field Pipe Line Sizes, Max.-Min.	8-4	24-10	10-6	20-10	24-6	10-6	20-6	8	24-8	10-4	19.
Original Reserves (MMcf)	--	—	5,331	8,662	31,581	—	19,586	3,640	—	9,247	20.
Base Gas - Cushion Gas Total (MMcf)	2,016	6,612	1,846	4,307	9,849	3,520	6,993	1,200	4,328	2,947	21.
Working Gas - Total (MMcf)	4,444	16,973	3,908	4,889	20,880	3,572	21,742	2,669	8,617	6,252	22.
Total Base Gas & Working Gas (MMcf)	6,460	23,585	5,754	9,196	30,729	7,092	28,735	3,869	12,945	9,199	23.
Future Undeveloped or Unused Capacity - Base Gas (MMcf)	0	0	0	0	—	0	0	0	—	—	24.
Future Undeveloped or Unused Capacity - Working Gas (MMcf)	936	1,583	523	3,936	—	3,522	946	475	—	—	25.
Future Undeveloped or Unused Capacity - Total (MMcf)	936	1,583	523	3,936	—	3,522	946	475	—	—	26.
Ultimate Storage Capacity (MMcf) (If Aquifer, Total Developed Capacity)	6,499	23,496	5,733	9,146	31,098	7,088	28,703	3,827	—	9,336	27.
Designed Maximum Deliverability (Mcf/D)	10,000	200,000	18,000	580,000	210,000	20,000	270,000	60,000	—	60,000	28.
Maximum Storage Pressure (psig)	1,003	1,104	980	980	980	956	1,250	1,009	—	980	29.

SOURCES: (5),(6)

NOTES:
a. Included under Payne Pool.
b. Also serves Dawn 167 Pool.
c. Also shared by Dawn 59-85, Dawn 156, Waubuno and Terminus Pools.
d. Included under Dawn 47-49 Pool.
e. Included under Bickford Pool.
f. Also shared by Bentpath and Rosedale Pools.
g. Included under Payne Pool.
h. Included under Dawn 47-49 Pool.

TABLE 2-2

Union Gas Limited
Schedule of Official Storage Capacities-Metric

	CURRENT CAPACITY					"PLANNED" CAPACITY					
	Cushion		Total			Cushion		Total			
Pool Name	Press.	Inv.	Press.	Inv.	Working Capacity	Press.	Inv.	Press.	Inv.	Working Capacity	Added Working Capacity
59-85	3,447	122,000	6,856	260,500	138,500	2,100	72,000	7,300	279,900	207,700	69,200
47-49	2,413	52,300	6,856	163,000	110,700	2,100	45,200	7,300	175,100	129,900	19,200
Payne	2,413	198,100	8,718	814,000	615,900	2,100	171,300	8,900	833,700	662,400	46,500
156	2,413	279,000	6,856	870,500	591,500	2,100	241,200	7,600	979,100	737,900	146,400
Waubuno	2,413	83,500	6,856	260,600	177,100	2,100	72,200	8,400	328,900	256,700	79,600
Bickford	2,413	187,300	7,711	668,100	480,800	2,100	161,900	8,300	727,100	565,200	84,400
Terminus	2,512	122,600	6,856	366,700	244,100	2,100	101,600	7,400	400,100	298,500	54,400
Bentpath	2,413	57,100	7,015	183,000	125,900	2,100	49,400	7,600	200,500	151,100	25,200
Rosedale	2,413	34,000	7,056	109,600	75,600	2,100	29,400	7,600	119,400	90,000	14,400
167	3,547	99,700	6,691	200,900	101,200	2,100	57,200	7,200	218,400	161,200	60,000
TOTAL		1,236,600		3,896,900	2,661,300		1,001,600		4,262,200	3,260,600	599,300

NOTES: (1) All pressures are kPaa. All inventories are 10^3m^3.
(2) "Planned" capacities are based on anticipated future cushion pressures and on PMOP's corresponding to a 0.70 psi/ft. gradient in the pools.

SOURCE: Union Gas Limited.

TABLE 2-3

Union Gas Limited
Schedule of Official Storage Capacities-Imperial

	CURRENT CAPACITY					"PLANNED" CAPACITY					
	Cushion		Total			Cushion		Total			
Pool Name	Press.	Inv.	Press.	Inv.	Working Capacity	Press.	Inv.	Press.	Inv.	Working Capacity	Added Working Capacity
59-85	500.0	4,307	994.4	9,196	4,889	304.6	2,549	1,058.8	9,881	7,332	2,443
47-49	350.0	1,846	994.4	5,754	3,908	304.6	1,595	1,058.8	6,181	4,586	678
Payne	350.0	6,993	1,264.4	28,735	21,742	304.6	6,047	1,290.8	29,430	23,383	1,641
156	350.0	9,849	994.4	30,729	20,880	304.6	8,514	1,102.3	34,563	26,049	5,169
Waubuno	350.0	2,947	994.4	9,199	6,252	304.6	2,549	1,218.3	11,610	9,061	2,809
Bickford	350.0	6,612	1,118.4	23,585	16,973	304.6	5,715	1,203.8	25,667	19,952	2,979
Terminus	364.4	4,328	994.4	12,945	8,617	304.6	3,587	1,073.3	14,124	10,537	1,920
Bentpath	350.0	2,016	1,017.4	6,460	4,444	304.6	1,744	1,102.3	7,078	5,334	890
Rosedale	350.0	1,200	1,023.4	3,869	2,669	304.6	1,038	1,102.3	4,215	3,177	508
167	514.4	3,520	970.4	7,092	3,572	304.6	2,019	1,044.3	7,710	5,691	2,119
TOTAL		43,618		137,564	93,946		35,357		150,459	115,102	21,156

NOTES: (1) All pressures are psia. All inventories are MMCF.
The data contained in this table are rounded versions of the official metric values.
(2) "Planned" capacities are based on anticipated future cushion pressures and on PMOP's corresponding to a 0.70 psi/ft. gradient in the pools.

SOURCE: Union Gas Limited.

monenco

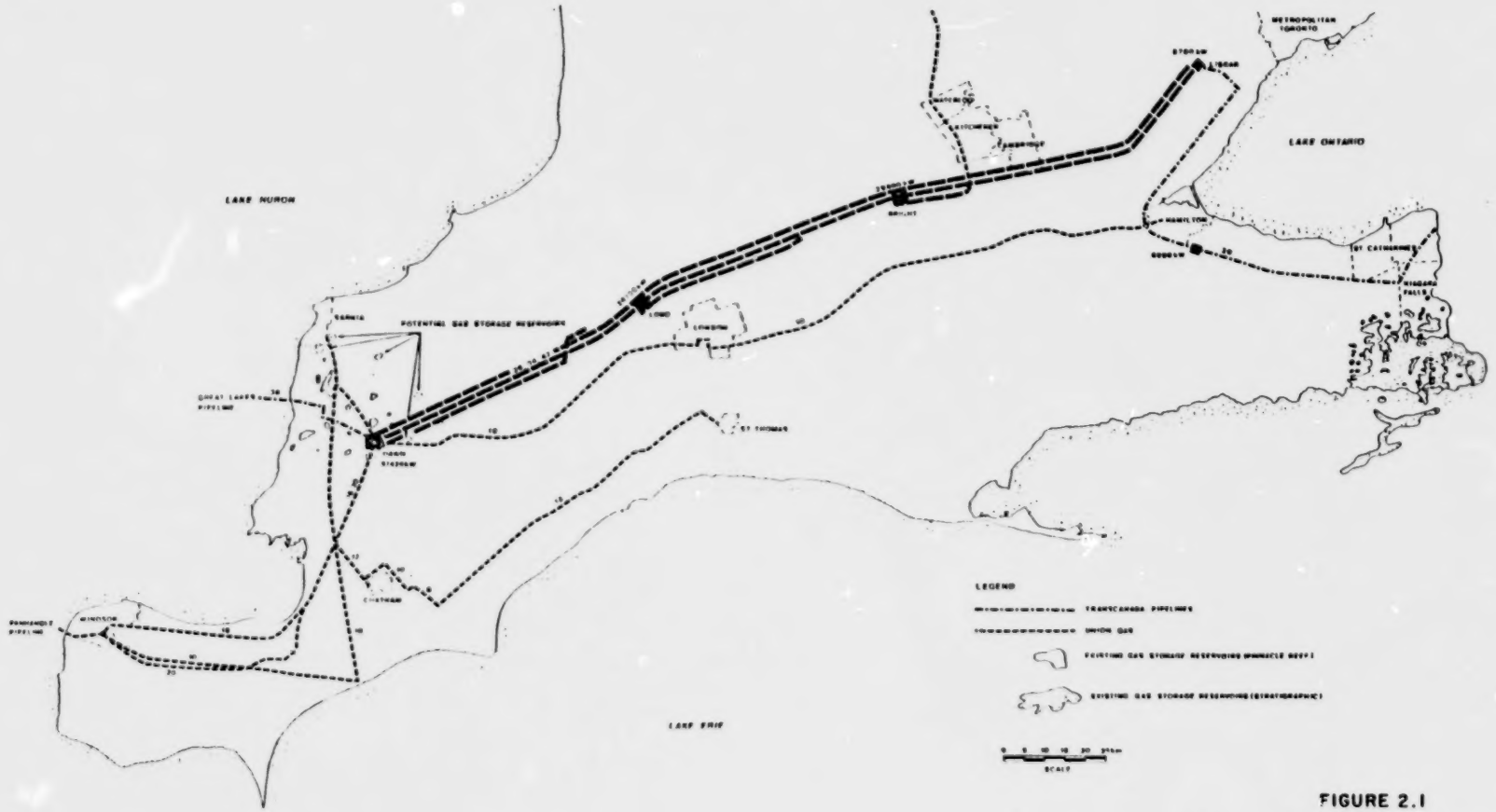

FIGURE 2.1

ONTARIO MINISTRY OF ENERGY

GAS TRANSMISSION AND STORAGE FACILITIES IN SOUTHWESTERN ONTARIO

JUNE 1986

TABLE 2-

Tecumseh Gas Storage Limited and Consumers' Gas Company
Underground Gas Storage Facilities

	Tecumseh Gas Storage Limited				Consumers' Gas Company	
Reservoir Name	Corunna	Kimball-Colvinville	Seckerton	Wilkesport	Crowland	1.
County	Lambton	Lambton	Lambton	Lambton	Welland	2.
Discovery Year	1950	1947	1952	1965	1951	3.
Year Activated for Storage	1964	1965	1964	1978	1962	4.
Storage Formation Name	Guelph	Guelph	Guelph	Salina-Guelph	Whirpool	5.
Geologic Age	Silurian	Silurian	Silurian	Silurian	Silurian	6.
Original Content	Oil & Gas	Gas	Oil & Gas	Gas	Gas	7.
Average Pay Thickness of Storage Formation (feet)	300	300	300	230	14	8.
Type of Geologic Trap	Pinnacle Reef	Pinnacle Reef	Pinnacle Reef	Pinnacle Reef	Stratigraphic	9.
Maximum Depth (feet)	-1,720	-1,650	-1,720	-1,212	700 avg.	10.
Minimum Depth (feet)	(Subsea)	(Subsea)	(Subsea)	(Subsea)	--	11.
Original Pressure (psig)	938	893	938	925	450	12.
Approximate Acreage Reservoir Limits	238	2,011	470	648	700	13.
Total	472	4,362	1,764	1,005	1,800	14.
No. of Output and/or Input Wells	5	42	16	7	18	15.
No. of Pressure Control and/or Observation Wells	1	6	1	2	23	16.
Total Wells	6	48	17	9	41	17.
No. of Compressor Stations	1	a	a	a	1	18.
Horsepower of Compressor Stations	32,500	a	a	a	800	19.
Field Pipe Line Sizes, Max.-Min.	16-12	24-20	20-16	16-10	8-4	20.
Original Reserves (MMcf)	5,615	44,000	13,028	8,600	500	21.
Base Gas - Native (MMcf)	2,178	9,211	3,350	64	83	22.
Base Gas - Injected (MMcf)	675	6,589	2,443	2,689	217	23.
Base Gas - Total (MMcf)	2,853	15,810	5,793	2,753	300	24.
Working Gas - Native (MMcf)	0	0	0	0	0	25.
Working Gas - Injected (MMcf)	771	39,736	5,613	5,872	439	26.
Working Gas - Total (MMcf)	771	39,736	5,613	5,872	439	27.
Total Base Gas & Working Gas (MMcf)	3,624	55,546	11,406	8,625	739	28.
Future Undeveloped or Unused Capacity - Base Gas (MMcf)	--	--	--	--	--	29.
Future Undeveloped or Unused Capacity - Working Gas (MMcf)	--	--	--	--	--	30.
Future Undeveloped or Unused Capacity - Total (MMcf)	--	--	--	--	--	31.
Ultimate Storage Capacity (MMcf) (If Aquifer, Total Developed Capacity)	--	--	--	--	739	32.
Designed Maximum Deliverability (Mcf/D)	--	--	--	--	35,000	33.
Maximum Storage Pressure (psig)	--	--	--	--	500	34.

a. Included under Corunna Reservoir

SOURCE: (5)

2.4 CONSUMERS' GAS COMPANY

At present, only one underground storage facility is being operated by Consumers'. The Crowland facility, unlike the Union and Tecumseh facilities, is located in the Niagara Peninsula in Welland County. Its current working storage capacity is 12.5 $10^6 m^3$ (439 MMcf). A summary of the Crowland facility is provided in Table 2-4.

2.5 ICG UTILITIES (ONTARIO) LIMITED

ICG has operated a liquefied natural gas (LNG) storage facility at Hagar, Ontario since 1968. The storage capacity is 17.3 $10^6 m^3$ (609 MMcf) with a maximum sendout rate of 2.5 $10^6 m^3$/day (90 MMcf/d). The plant is used to peak shave ICG's Northern Zone which includes the Sudbury-Espanola areas.

PART 3

GEOLOGY OF ONTARIO

3.1 GENERAL GEOLOGY OF ONTARIO

The geology of Ontario is dominated by the Precambrian crystalline igneous and metamorphic rocks of the Superior, Southern and Grenville Provinces of the Canadian Shield. The Superior Province in Ontario consists of batholithic intrusions separated by easterly trending folded and faulted metasedimentary and metavolcanic units. The Southern Province, characterized by easterly trending folds, lies partly along the north shores of Lake Superior and Lake Huron, and is separated from the Superior Province by an unconformity. The Grenville Province in Ontario lies south of a line running northeast from the north end of Georgian Bay. It is bounded on the northwest by the orogenic Grenville Front and is characterized by extremely complex folding.

Paleozoic rocks are confined to three general areas, of two depositional regions. The Hudson Bay Platform contains rocks of Upper Ordovician to middle Devonian age from about midway up the northwestern Ontario border to the southern tip of James Bay. These rocks are representative of the ancient Hudson Bay and Moose River Basins. The St. Lawrence Platform, in Ontario separated into two areas by the Precambrian Frontenac Arch, contains rocks of Upper Cambrian to Upper Devonian age. It is representative of the Michigan Basin and Appalachian (or Allegheny) Basin south of a line approximately from Midland to Kingston, and the Ottawa Embayment of the Quebec Basin east of Brockville.

The Hudson Bay and Moose River Sedimentary Basins, separated by the Archean Cape Henrietta Maria Arch, was formed during several episodes of submergence and marine deposition in subsiding areas of the Precambrian basement during the early Paleozoic (Figure 3-1). The oldest Paleozoic rocks in these Basins are those of the Upper

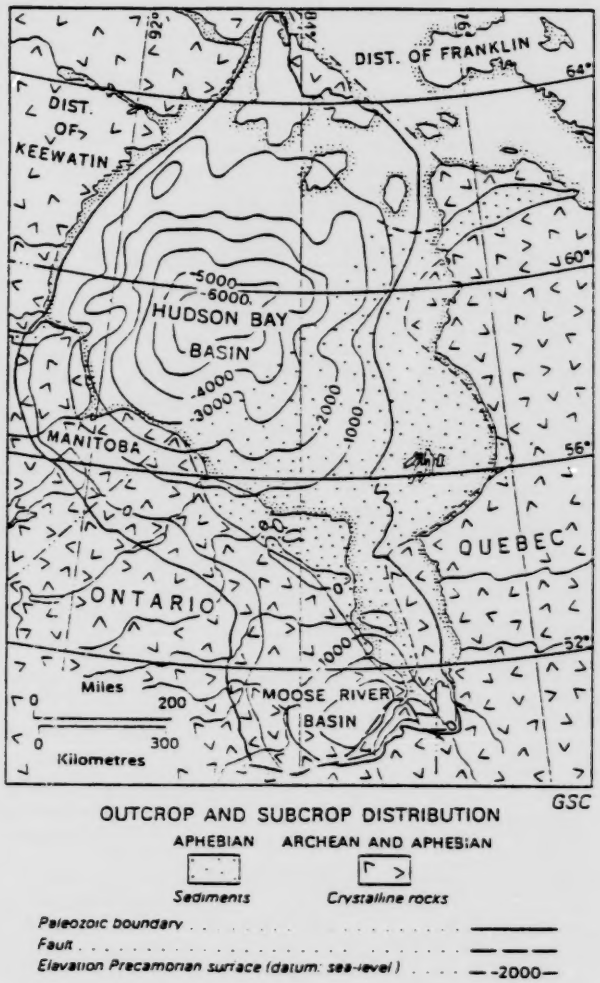

Figure 3-1. Basement evaluations for Hudson Bay and Moose River Basins. From Sanford and Norris, 1976. Pg. 137.

Ordovician Bed Cache Rapids Group (Figure 3-2). They are microcrystalline to finely crystalline dolomitic limestones 150 feet thick, with basal calcareous sandstone in southern Hudson Bay Basin, thickening toward the Moose River Basin. Thicknesses approach 270 feet in the Moose River Basin. The Churchill River Group unconformably overlies the Bad Cache Rapids and consists of about 200 feet of microcrystalline and cryptocrystalline dolomitic limestone thickening and grading southeastward into sucrosic dolomite with interbeds of gypsum and anhydrite.

The Lower Silurian Severn River Formation is a thick (700 feet) sequence of aphanitic limestone and dolomite thinning in Moose River Basin to 170 feet with local coarse clastic limestone and flat pebble conglomerate beds. Ekwan River and Attawapiskat Formations, in part laterally equivalent, consist of 300 feet of medium crystalline, locally biostromal limestone and dolomite, overlain by a reef complex of vuggy limestone, bioherms of carbonate and bioclastic detritus grading to finer, thinly bedded interreef facies, and a blanket of thick biostromal beds of massive vuggy limestone and dolomite. The reef structure is coeval with and lithologically similar to the oil and gas producing Guelph Formation of the St. Lawrence Platform. A sequence of dolomite with gypsum and anhydrite interbeds, enveloping gypsiferous red/green siltstone and sandstone, makes up the Upper Silurian Kenogomi River Formation. Its thickness at Moose River Basin is 850 feet, thinning to 600 feet in Hudson Bay Basin.

Following the widespread Lower Silurian uplift, deposition resumed in Middle Silurian. The Sextant Formation (continental) and Stooping River Formation (marine) consist of finely crystalline and cherty limestone and dolomite grading to and transgressing shales, siltstones, coarse sands and conglomerates in southern Moose River Basin. Four limestone formations with minor shale and evaporites, totalling 700 feet, overlie the Sextant/Stooping River in Moose River Basin. Only the lower formation exists in onshore Hudson Bay Basin

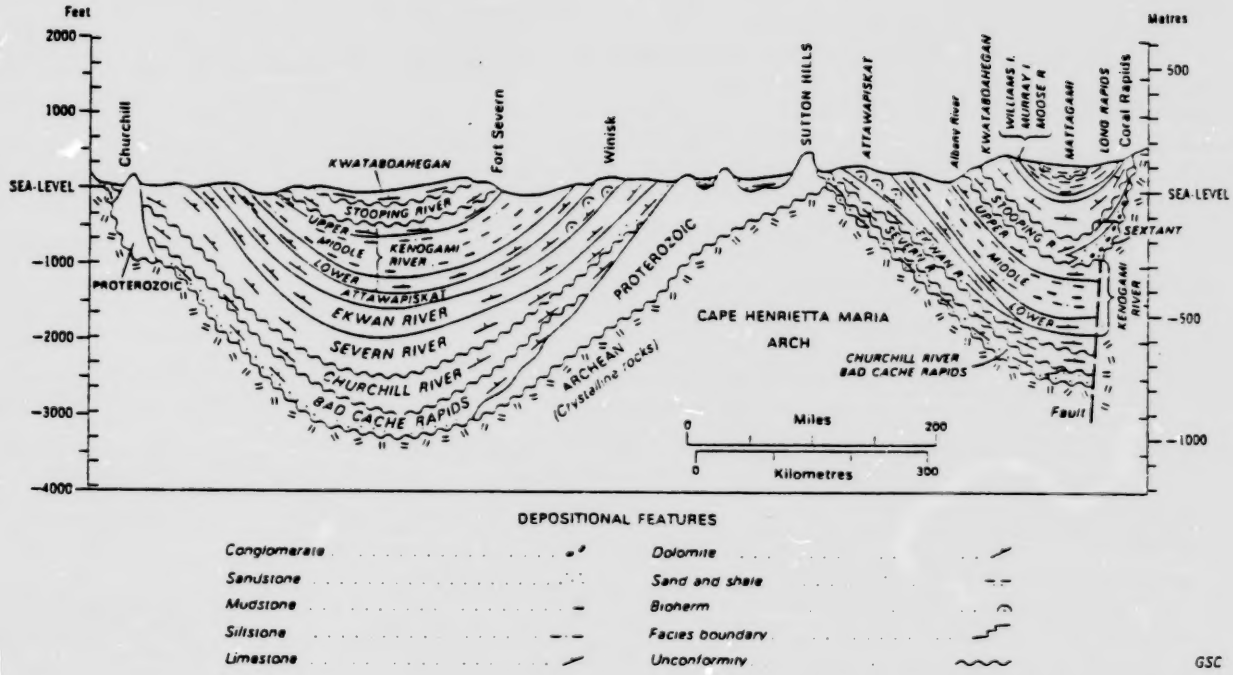

Figure 3-2. Cross-section of Paleozoic rocks of the Hudson Bay and Moose River Basins at the southern Hudson Platform. From Sanford and Norris, 1976. Pg. 138.

and is the youngest Paleozoic unit there. The Long Rapids Formation, 285 feet of black and brown carbonaceous shales coeval with the Kettle Point Formation of St. Lawrence Platform, completes the Paleozoic section in Moose River Basin.

Lower Cretaceous clays, white quartz sands, micaceous sands and lignite seams of the Mattagami Formation are recognized only in Moose River Basin.

The Michigan Basin, centred in central Michigan (Figure 3-3), is a sedimentary basin that underwent active rapid subsidence in the early Paleozoic, and contains deposits of Cambrian to Pennsylvanian in age. The outermost deposits attributable to the Michigan Basin in Ontario are at northern Lake Huron and Manitoulin Island, the Bruce Peninsula, and through Southern Ontario as far east and south as the Algonquin Arch, a structural high in the Precambrian basement trending southwest through Essex County. At their thickest, sediments of the Michigan Basin reach approximately 14,000 feet(1), but in Ontario reach a maximum of 5,900 feet, in the Lake St. Clair region. Middle Silurian reefal beds of the Michigan Basin are oil and gas producers, and Upper Silurian beds contain significant thicknesses of salt.

Separated from the Michigan Basin by the Algonquin Arch, the Appalachian Basin lies southeast of Lakes Ontario and Erie, in the States of New York, Pennsylvania, and Ohio. While total sediment thicknesses in the Basin reach 35,000 feet(1), the Niagara Peninsula, on the Basin's edge, has only about 4,900 feet. The stratigraphy and lithology of Appalachian Basin rocks in Ontario is very similar to that of the Michigan Basin. Gas occurs in Lower and Middle Silurian sandstones.

The Ottawa Embayment of the Quebec Basin is the easternmost occurrence of Paleozoic deposition in Ontario. It consists of a thick Upper Cambrian sandstone unit, overlain by Ordovician limestones and shales of a number of formations to a total thickness of about 3,500 feet.

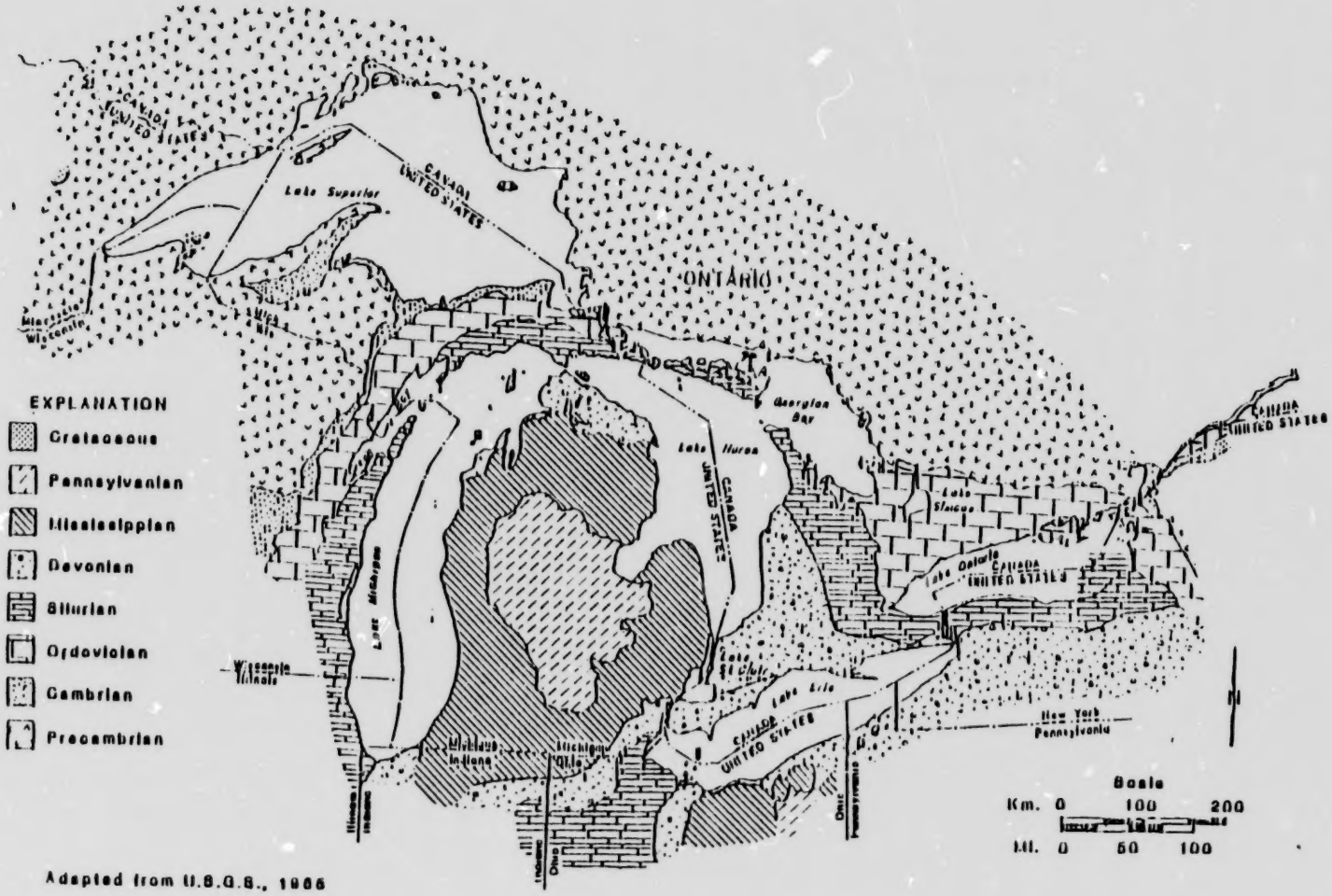

Figure 3. Geologic Map of the Great Lakes Region

FIGURE 3-3

3.2 REGIONAL GEOLOGY OF SOUTHWESTERN ONTARIO

The geology of southwestern Ontario is influenced by several isostatic and tectonic features of the underlying Precambrian basement. The Algonquin and Findlay Arches form linear basement highs from south of Georgian Bay southwestward through western Lake Erie and beyond. They are separated by the Chatham Sag, a low point on the linear structure. Isostatic subsidence occurred on both sides of the Arches, forming the Michigan Basin to the northwest, and the Appalachian, or Allegheny, Basin to the southeast. Paleozoic deposition in southwestern Ontario was influenced and controlled by these features and events, as sedimentary strata are thinnest over the Algonquin Arch, and thicker toward the Michigan and Appalachian Basins. Regional dips are shallow (approximately 1%) and are similar toward each Basin(1). Quaternary deposits of glacial and lacustrine origin cover the Paleozoic strata in varying thicknesses.

The earliest Paleozoic rocks are upper Cambrian sandstones and dolomites of the Michigan and Appalachian Basins. These formations are erosionally truncated against the Algonquin Arch, and reach total thicknesses of 350 feet in Michigan Basin and 600 feet in Appalachian Basin(3).

Lower Ordovician rocks are absent from the Ontario record, although they exist basinward in Michigan Basin. Rocks of Middle Ordovician to Upper Devonian age trangress the Algonquin Arch but are thinnest over the Arch and thicken toward the Michigan and Appalachian Basins. Devonian age rocks are absent in the northern marginal regions of the Michigan Basin at Manitoulin Island and Bruce Peninsula. Figure 3-4 shows the bedrock geology of southern Ontario.

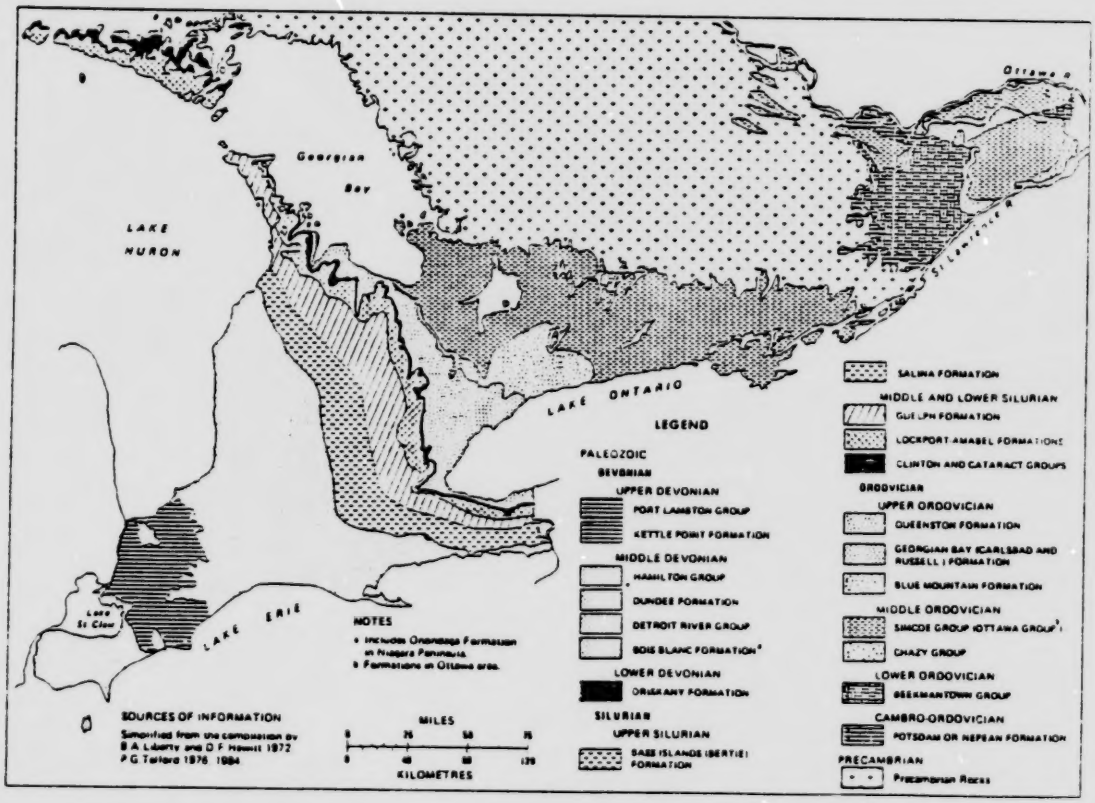

Figure 3-4. Bedrock geology of Southern Ontario. From Chapman and Putnam, 1984. Pg. 2.

Middle Ordovician Black River and Trenton Groups consist primarily of lithographic to coarse clastic limestones with interbeds of pelletoidal limestone, dolomite, and clays. The basal Shadow Lake Formation of the Black River Group is a thin transgressive unit consisting of red and green shale, siltstone, and minor limestone and dolomite. Total thicknesses of 700 feet are encountered over Algonquin Arch and thicken to over 900 feet southeastward and northwestward(3,4).

Upper Ordovician deposits conformably overlie the Trenton Group and are dominated by shaly deposition. Black euxinic shale of the Collingwood Formation is overlain by dark grey and brown shales of the Blue Mountain Formation. The Meaford-Dundas Formation consists of shales and siltstones with minor limestone beds. The upper Queenston Formation is a semi-continental red shale and siltstone thickest in the Appalachian Basin, and thinning over the Algonquin Arch and into the Michigan Basin. Latest Ordovician rocks are absent and presumed eroded.

The Lower Silurian Cataract Group reflects a transgressive/regressive cycle of fine clastics grading to shaly dolomite and dolomite from the Appalachian Basin northward and westward, overlain by shales and red sandstone in the Appalachian Basin, grading to shales northward and westward. In Middle Silurian, the Clinton Group consists of a thin deposit of crystalline dolomite, with occasional coral biostromes and lenses. The Lockport/Amabel Formations consist of coarsely crystalline crinoidal dolomite at the Algonquin Arch and grade to cherty fine-grained dolomite toward Michigan Basin, and silty, dolomitic shales toward Appalachian Basin. The crinoidal banks are thickest over the Algonquin Arch, and thin toward the Basins.

In Late Middle to Upper Silurian, barrier reefs completely fringing the Michigan Basin developed. Coarsely crystalline dolomite of the Guelph Formation developed to thicknesses of greater than 300 feet over the Algonquin Arch, thinning and grading to bituminous and cherty dolomite basinwards. Large bioherm patch reefs developed adjacent to the barrier reef in Michigan Basin with vertical relief of up to 160 feet. Toward the centre of the basin, where subsidence was more rapid, pinnacle reefs with vertical relief of as much as 550 feet developed(3,4). Figure 3-5 shows Guelph facies in Ontario. Small-scale, scattered, bioherms also occur within Guelph strata southeastward from Algonquin Arch, in Appalachian Basin.

With development of the Guelph reef complex, circulation of Michigan Basin waters became restricted and evaporitic deposition became significant. The Salina Formation comprises these evaporite, carbonate, and clastic sequences, thickest at Michigan Basin and thinning toward the Algonquin Arch. Interbedded shales, dolomites, and salt grade to dolomite, shale and anhydrite over the Arch, and dolomite, shale, and gypsum in the Appalachian Basin. Beds of the Salina Formation drape the patch and pinnacle reefs of the Guelph Formation (Figure 3-6). Finely sucrosic dolomite of the Bass Island/ Bertie Formation blanket the Salina, and are the youngest Silurian beds. They are thickest in Michigan Basin, and thinnest over Algonquin Arch.

The Lower Devonian was characterized by uplift and erosion. The record is preserved only as erosional remnants of an orthoquartzitic sandstone in the Niagara Peninsula. Middle Devonian rocks are represented by a basal bed of finely crystalline, silty, and cherty limestone. It is thickest at Michigan Basin. The Detroit River Group consists of a lower unit of brown sucrosic dolomite thinning and grading eastward to coarse crinoidal and coral limestone. Bioherm reefs of up to 90 feet relief occur in this unit. It is overlain by finely crystalline dolomite with thin interbeds of anhydrite. Coarse

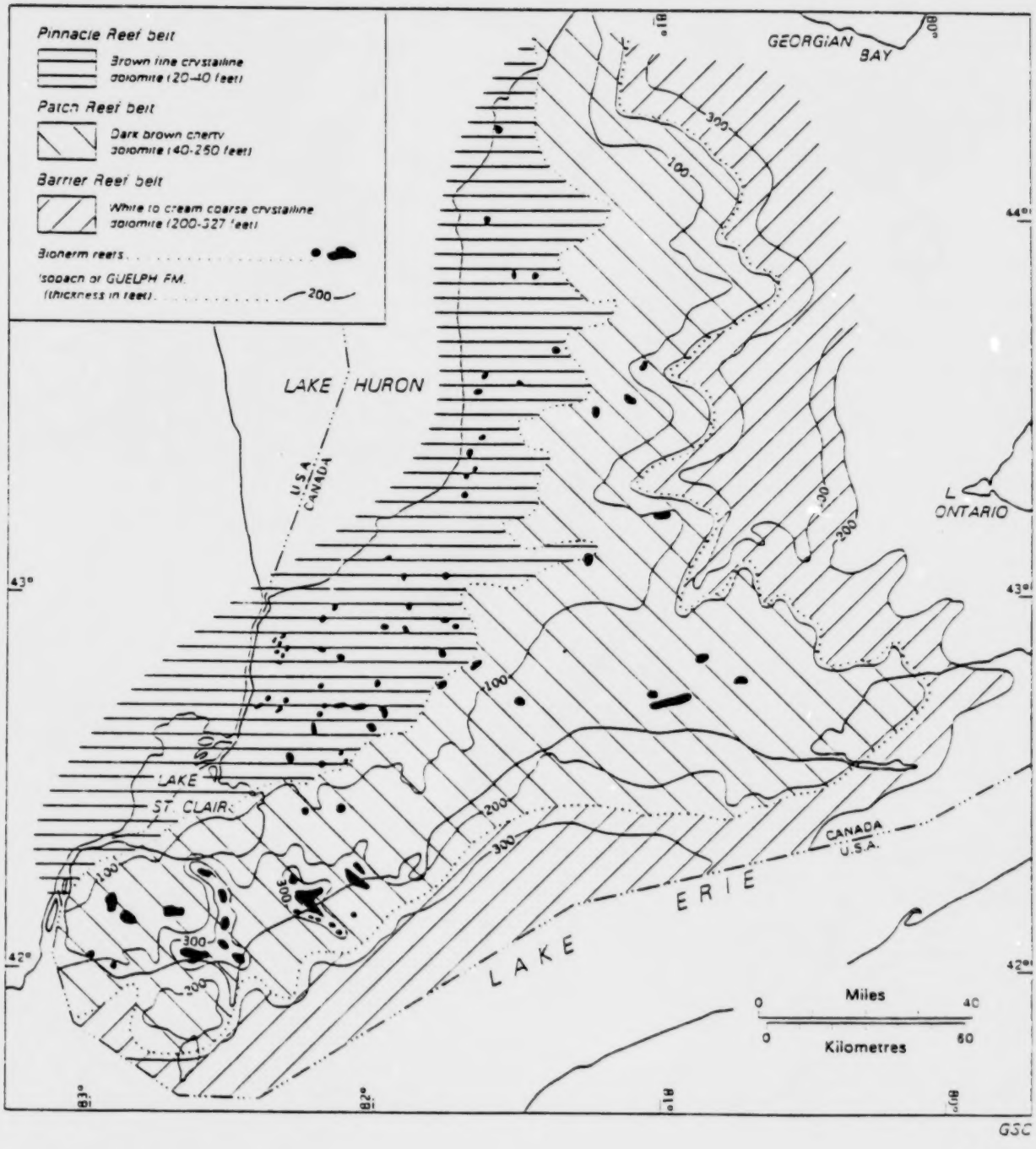

Figure 3-5. Facies of the Silurian Guelph Formation, southwestern Ontario. From Sanford, 1976. Page 349.

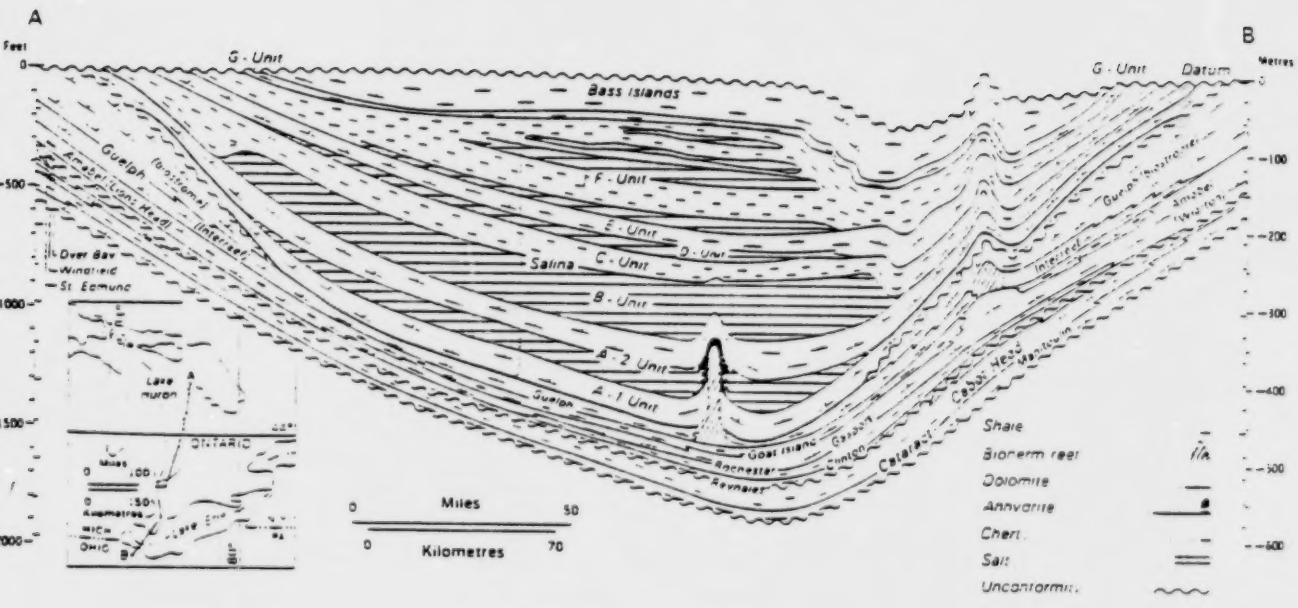

Figure 3-6. Cross-section of Silurian strata, eastern flank of Michigan Basin, southwestern Ontario. From Sanford, 1976. Page 270.

crinoidal and finely crystalline limestone of the Dundee Formation unconformably overlie the above sequence. Shales, grading upward to limestone, comprise the Hamilton Group.

Upper Devonian deposits consist of shales of the Kettle Point Formation, black and dark brown bituminous shales with interbeds of green shale, overlain conformably in the Michigan Basin by three formations of shale, sandstone, and shale totalling 200 feet at southern Lake Huron. The Kettle Point thins from 300 feet near Sarnia, over the Algonquin Arch, and thickens to more than 1000 feet in the Appalachian Basin south of Lake Erie.

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(3) Poole.

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PART 4

THE GEOLOGY OF GAS STORAGE

4.1 CANADIAN OVERVIEW

In Canada, to a large extent, the major natural gas reserves are located great distances from the major consuming regions. As a result, long distance transmission pipelines are needed to convey the gas to its market. Underground storage is employed to improve pipeline load factors (maximizing throughput) while at the same time securing supply and balancing seasonal variations in demand(2). In Canada natural gas is stored underground only in Alberta, Saskatchewan and Ontario. Currently, 26 underground storage facilities are located in these three provinces, two in Alberta, nine in Saskatchewan and 15 in Ontario(7). In Alberta two depleted gas fields, Bow Island and Carbon are used for natural gas storage. The Bow Island field was activated for the storage in 1930 and the Carbon field, in 1968. Both these storage facilities are located in Cretaceous rock formations. In Saskatchewan five of the nine storage facilities are located in Cretaceous rock formations while the other four are salt caverns. These caverns, which are located in Devonian formations, were developed using solution mining. In Ontario 14 out of the 15 storage pools are pinnacle reef formations in Silurian rock. The exception, the Crowland Pool in the Niagara Peninsula which is a basal Silurian sandstone reservoir, is the only non-pinnacle reef storage formation presently being used in Ontario.

With the exception of the salt cavern storage formations, all of the remaining storage pools in Alberta, Saskatchewan and Ontario are depleted hydrocarbon reservoirs.

4.2 ONTARIO

4.2.1 LAMBTON COUNTY

In Ontario 14 out of the 15 operating gas storage pools are located in Lambton County. Each of these pools are pinnacle reef-type pools of the Silurian Guelph or Niagara (Michigan) Formation situated in the shelf environment along the east and southeast edge of the Michigan Basin. The greatest development of these reef pools has occurred in Lambton County.

The pinnacle reefs are mound-like structures consisting of rock formed by the remnants of ancient sea life which existed in the large shallow oceans in the Michigan Basin during the Silurian period - some 300 to 500 million years ago. The three most common types of reefs in Lambton County are:

- incipient, 9.1 to 15.2 m (30 to 50 feet) in vertical thickness;
- subdued, 15.2 to 45.7 m (50 to 150 feet); and
- pinnacle, 76.2 to 152.4 m (250 to 500 feet).

(OMNR Petroleum Resources Section, London). Due to the manner in which they are formed, pinnacle reefs tend to be porous and permeable. In Lambton County these reefs are enclosed in an impermeable rock-anhydrite. As a result, these reefs are ideally suited to underground storage of natural gas.

The Dawn 59-85 and Payne pools are typical reef pools and are used as examples of these formations in the following discussion. The Dawn pool has a depth to crest of reef of 481 m (1,579 feet) and a depth to base of gas of 572 m (1,876 feet) yielding a maximum gas pay

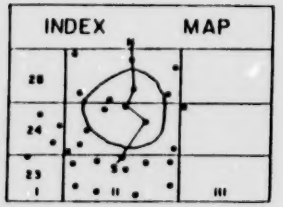
thickness of 91 m (297 feet). Its shape resembles that of an inverted saucer and has an approximate reservoir and designated area of 66 ha (163 acres) and 182 ha (450 acres), respectively (see Figure 4-1). The Payne Pool, which is similar in shape to the Dawn Pool (see Figure 4-2), has a depth to crest of reef of 598 m (1,963 feet) and a depth to base of gas of 714 m (2,341 feet) resulting in a maximum gas pay section of 116 m (378 feet). It has a reservoir area of about 155 ha (382 acres) and a designated gas storage area of 311 ha (768 acres).

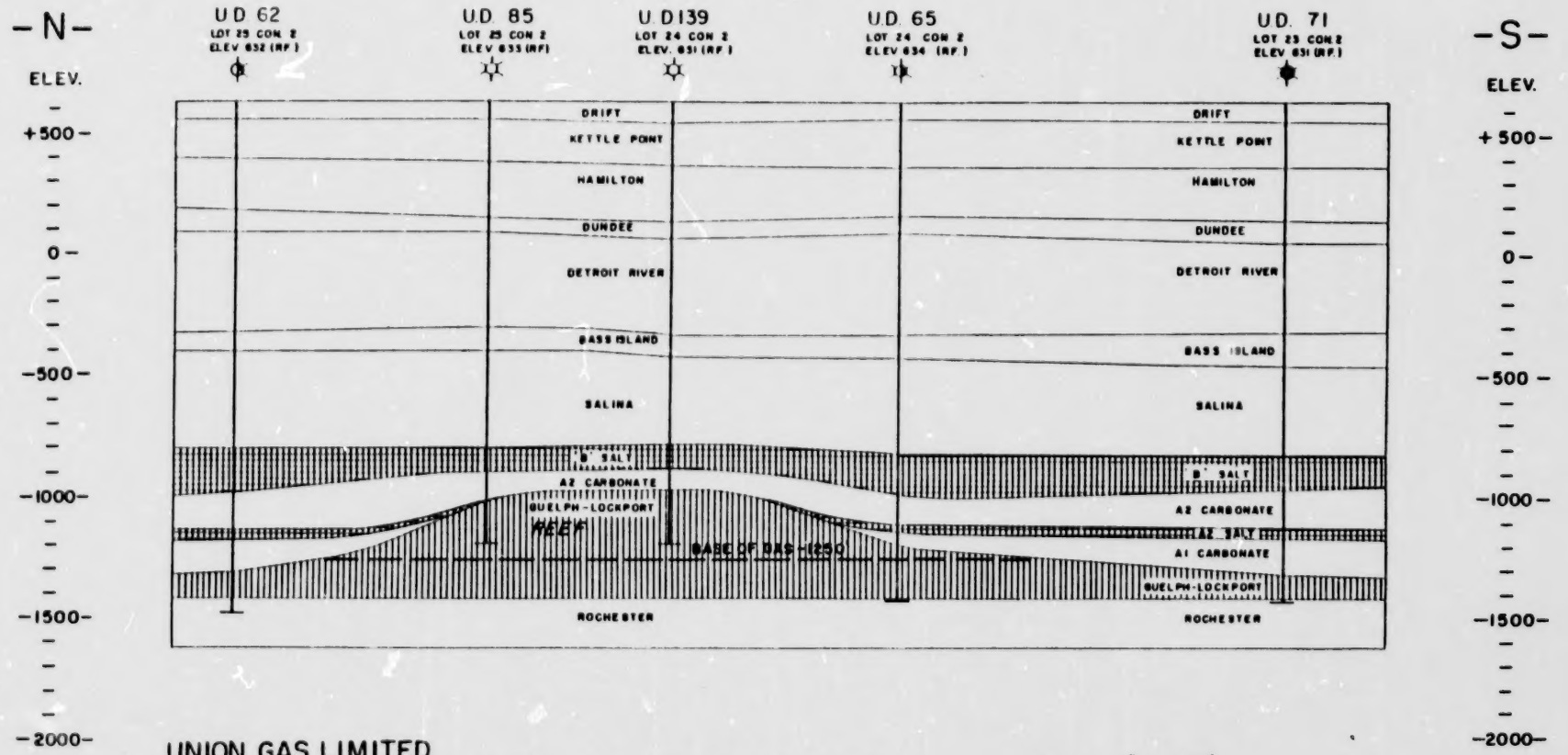
With respect to gas storage/delivery operating conditions, the Dawn 59-85 pool has one observation and seven deliverability wells. The current working storage capacity at 6,856 kPaa (994.4 psia wellhead) to a 3,447 kPaa (500 psia wellhead) cushion pressure is 138,500 10^3m^3 (4,889 MMcf) while the total current capacity at a planned maximum operating pressure of 6,856 kPaa (994.4 psia wellhead) is 260,500 10^3m^3 (9,196 MMcf) with a cushion volume of 122,000 10^3m^3 (4,307 MMcf). The maximum deliverability of the Dawm 59-85 Pool, as reported by Union, is 16,794 10^3m^3/day (593,000 Mcf/day) at a current maximum operating pressure of 6,856 kPaa (994.4 psia wellhead). The working gas to base gas ratio is 1.14 to provide greater deliverability. The Dawn 59-85 Pool is delta pressured (maximum operating pressure in excess of original discovery pressure) by 13.3%.

In comparison, the Payne Pool currently has two observation and ten deliverability wells. The current working storage capacity at a planned maximum operating pressure of 8,718 kPaa (1,264.4 psia) to a 2,413 kPaa (350 psia) cushion pressure (wellhead) is 615,900 10^3m^3 (21,742 MMcf) while the total current capacity at a planned maximum operating pressure of 8,718 kPaa (1,264.4 psia) is 814,000 10^3m^3 (28,735 MMcf) with a cushion volume of 198,000 10^3m^3 (6,993 MMcf). The maximum deliverability of the Payne Pool, as reported by Union is 8,100 10^3m^3/day (286,000 Mcf/day) at a current maximum operating pressure of 8,718 kPaa (1264.4 psia) wellhead. The working gas to base gas pressure ratio is 3.6. The Payne Pool is delta pressured by 23.5%.

FIGURE 4-1

DAWN 59-85 STORAGE POOL, VERTICAL CROSS-SECTION





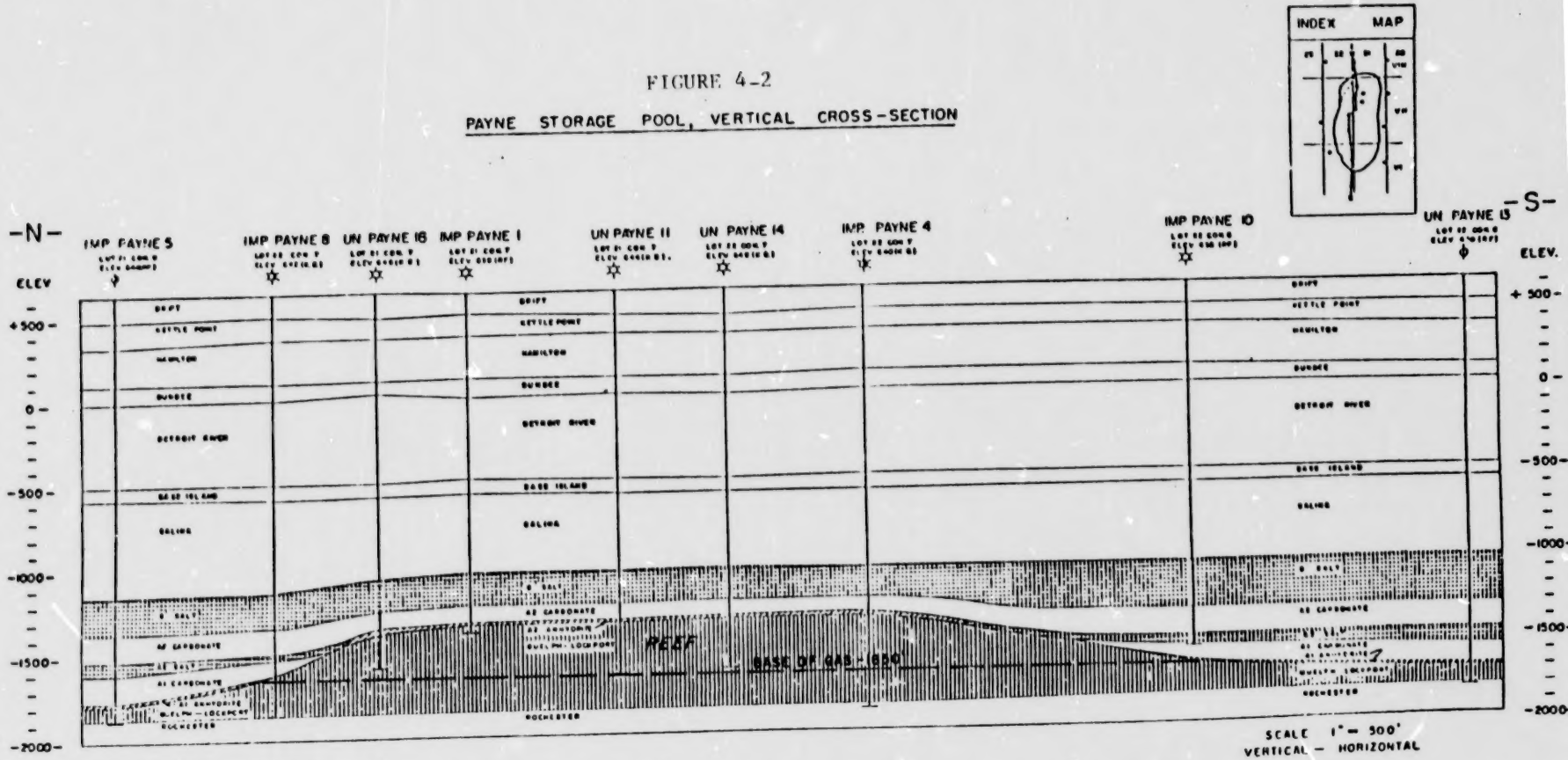
UNION GAS LIMITED

Legend: 0 deliverability gas wells
0 show of oil
0 dry hole

SCALE 1" = 500'
VERTICAL—HORIZONTAL

FIGURE 4-2

PAYNE STORAGE POOL, VERTICAL CROSS-SECTION



UNION GAS LIMITED

Legend: 0 deliverability gas wells

0 show of oil

0 dry hole

As can be seen from the foregoing discussion, although the two pools are similar geologically, the operation of the two storage pools is quite dissimilar. Union has drilled and completed and is currently drilling and completing additional deliverability wells in its operating storage pools.

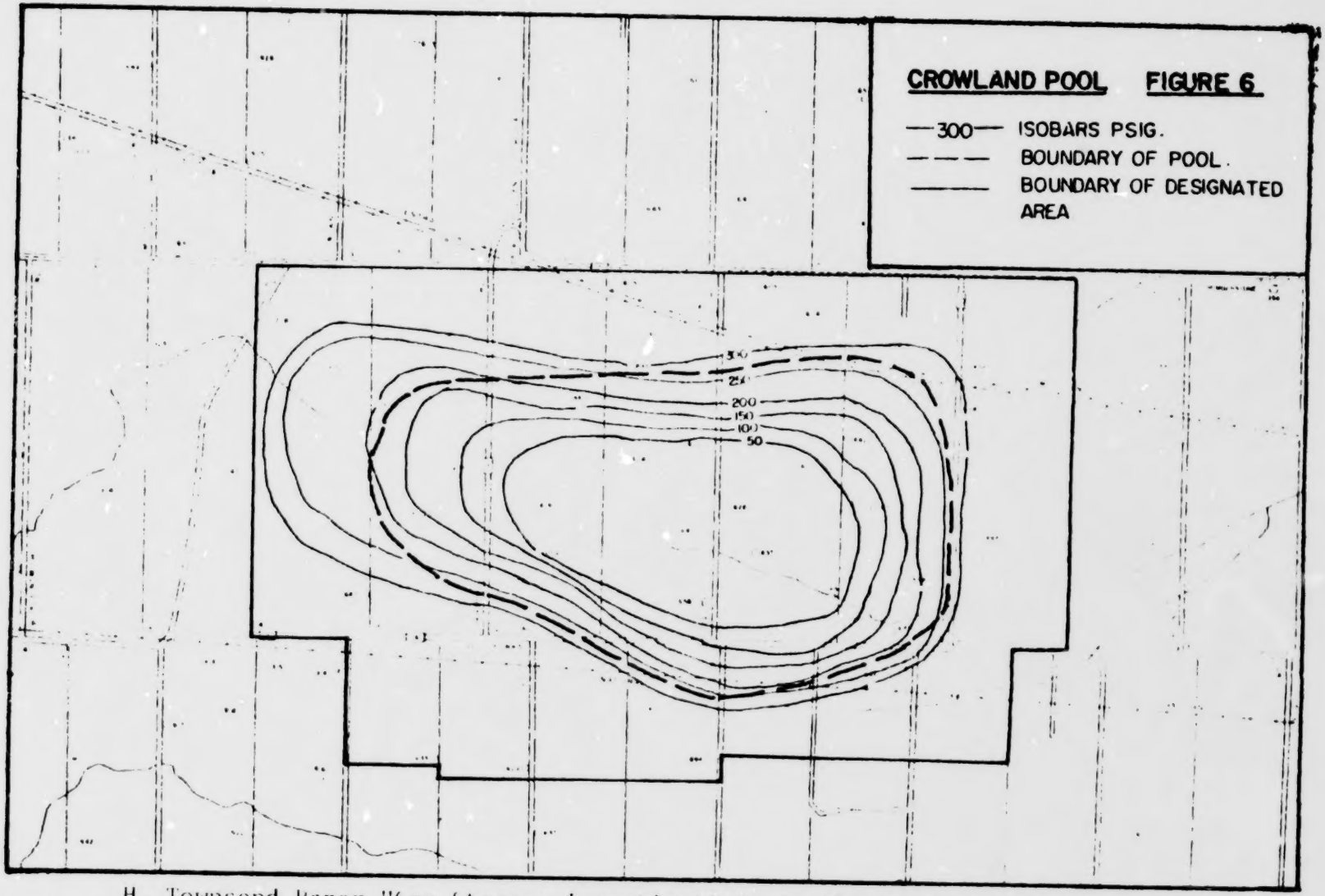
4.2.2 WELLAND COUNTY

The Crowland Pool, situated in Humber Township, Welland County, is operated by Consumers' Gas Company and is the sole non-pinnacle reef gas storage facility in use in Ontario. The storage formation is a sandstone of the Whirlpool Formation. The Whirlpool Formation is the lowermost horizon of the Silurian Clinton-Cataract group.

The Crowland Pool differs considerably from the pinnacle reef formations in Lambton County. For instance, the reefs have a gas pay zone in the order of 90 to 120 m (about 300 to 400 feet) while the Crowland Pool has a gas pay zone thickness of about 4.3 m (14 feet).

The maximum average depth to the gas pay zone is 213 m (700 feet). The approximate reservoir area is 283 ha (700 acres) while the total designated area is 729 ha (1,800 acres). The number of injection and withdrawal wells is 18 with 23 pressure observation wells. An isobar contour map of the pool is given in Figure 4-3.

Regarding its operation, the total volume of base gas in the pool is 8,500 10^3m^3 (300 MMcf) with a working storage capacity of 12,400 10^3m^3 (439 MMcf) for a total capacity of 20,900 10^3m^3 (739 MMcf) at a maximum storage pressure of 3,447 kPag (500 psig). The designed maximum deliverability of the pool is 990 10^3m^3/day (35,000 Mcf/day). The pool is delta pressured about 11%.



H. Townsend Paper "Gas Storage Investigations in the Niagara Peninsula, O.P.I. Annual Conference 1965".

4.3 CURRENT OPERATING GAS STORAGE POOLS

Figure 4-4 indicates the location of all gas storage pools currently being operated in Lambton County and several potential pools. Figure 4-5 shows the Tecumseh facilities in greater detail.

4.4 POTENTIAL GAS STORAGE

In assessing potential gas storage options for the Province of Ontario, all known subterranean methods for natural gas storage used presently in Canada and the United States have been investigated and are discussed below.

4.4.1 MINED CAVERN STORAGE

The storage of natural gas in mined caverns seems very unlikely in Ontario due to the high development costs that would be incurred. To prepare a cavern in Precambrian rock near the major natural gas markets in the Province or in the vicinity of either the Union Gas or Tecumseh compression plant facilities in Lambton County, about 915 m (3,000 feet) of Paleozoic sediments would be encountered before contacting Precambrian rock. Generally, mined caverns for natural gas storage have been considered feasible only in areas devoid of either natural porous rock storage fields (aquifers or depleted gas and oil fields) or salt beds which could be solution-mined to create salt caverns. Mined cavern storage is considered to have the least potential as a means of storing natural gas underground because less costly alternatives are available to the current operating storage companies in Ontario.

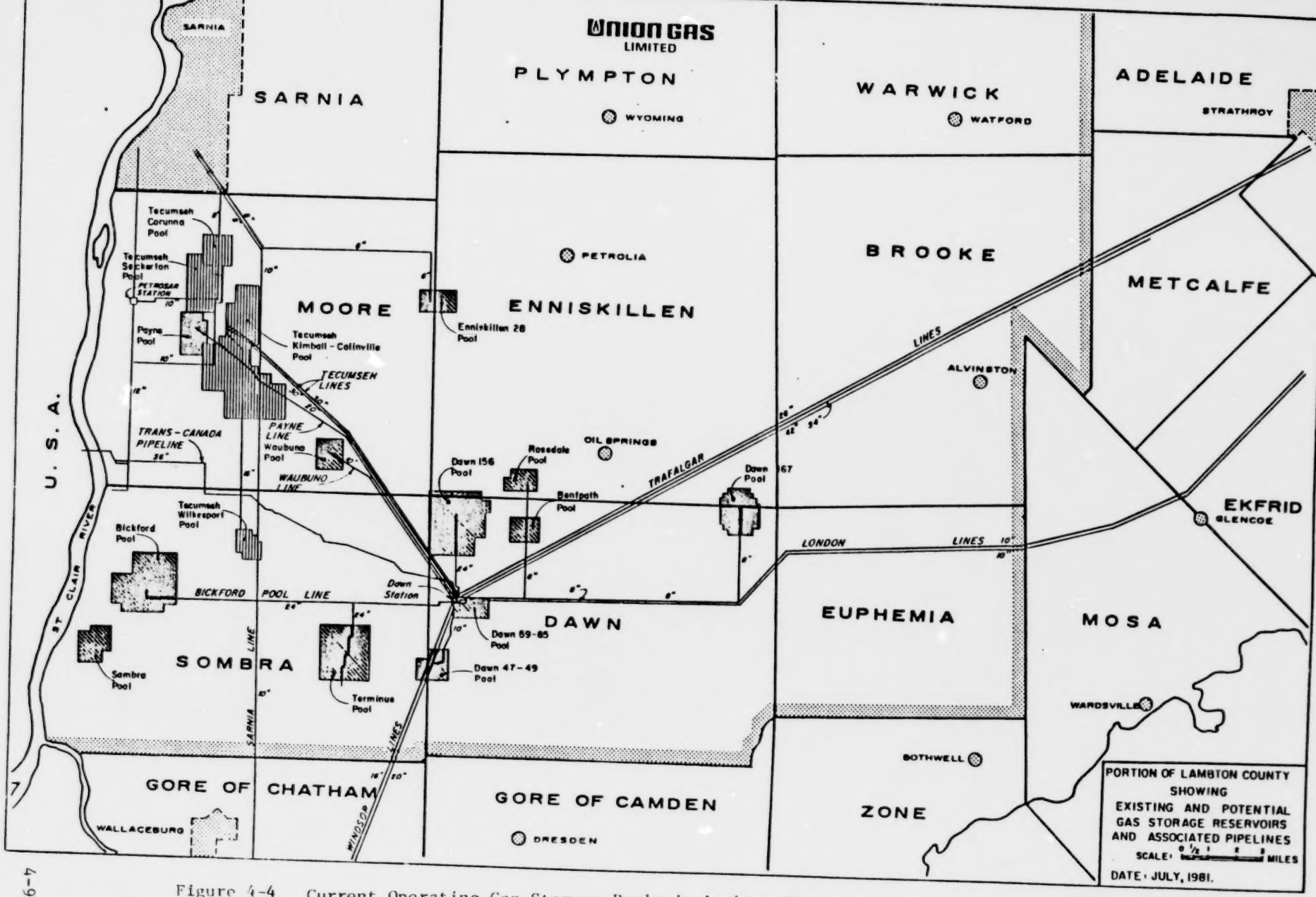
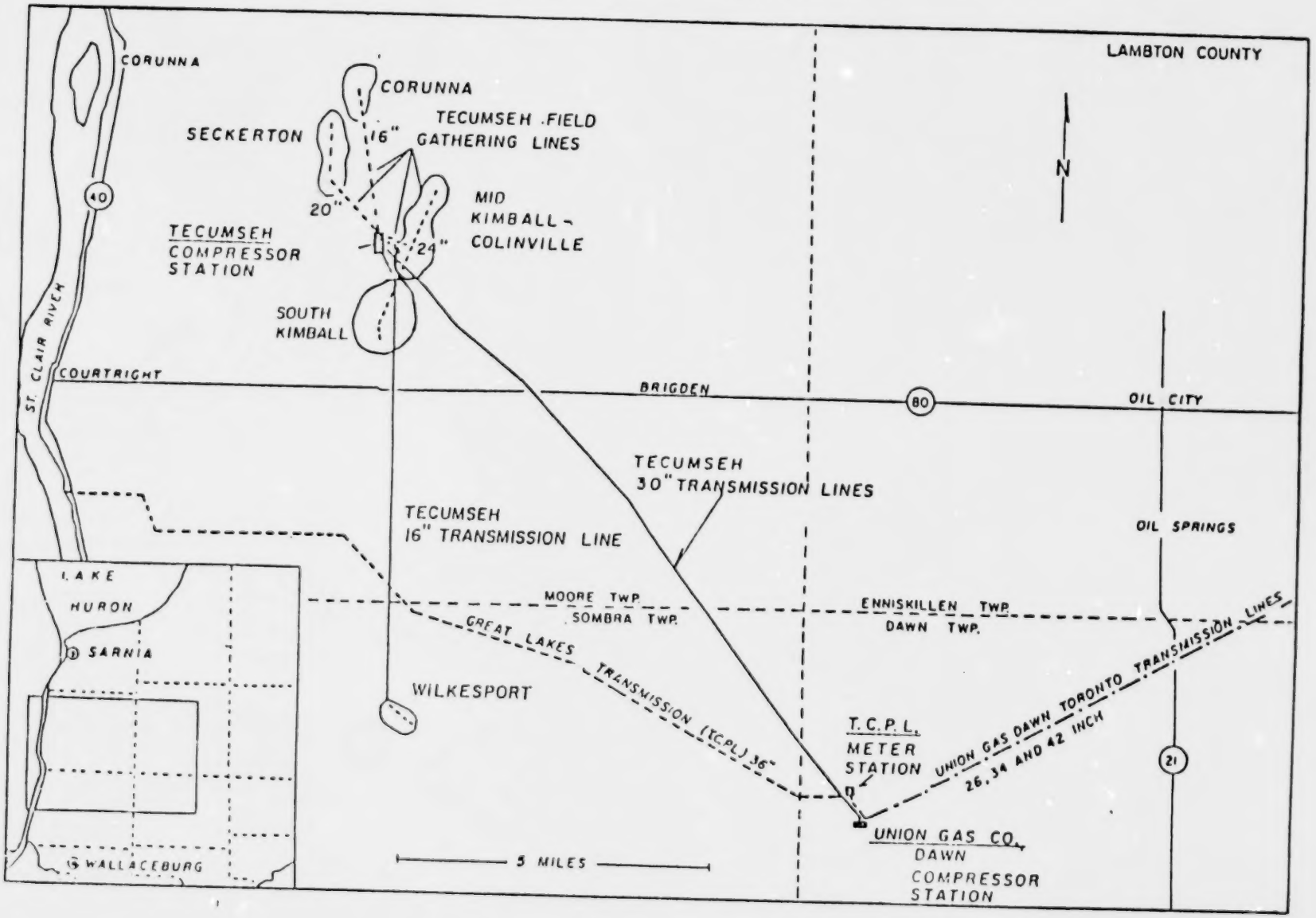


Figure 4-4 Current Operating Gas Storage Pools in Lambton County

Figure 4-5

TECUMSEH GAS STORAGE LIMITED
STORAGE RESERVOIRS



LOCATION MAP

4.4.2 AQUIFER STORAGE

In the absence of either depleted gas or oil fields or salt beds, aquifer storage of natural gas is considered to be the next best alternative. Aquifer-natural gas storage fields have been developed and used extensively and successfully, where gas storage is required near large markets, in states such as Illinois, Indiana and Iowa. The majority of the aquifer gas storage fields in the U.S.A. are in the Ordovician, Cambro-Ordovician and Cambrian formations which are the deeper sediments of the Paleozoic Era. There are now 52 aquifer natural gas storage pools in 10 states in the United States by 24 different companies (AGA Dec. 84 report)(3).

There may be some future potential of undeveloped aquifer gas storage in Ontario. Evaluation of such potential would require a special study in the Cambrian of Essex County initially. These sediments are generally at their deepest in the Sarnia/Windsor area.

4.4.3 CAMBRIAN STORAGE

In Ontario, the Cambrian sediments lie the furthest from the surface especially in southwestern Ontario and more specifically in the Sarnia area where the depth of one well, drilled to the base of the Cambrian section, was 1,477 m (4,847 feet). In Lambton County, Cambrian sediments are present only along the westerly portion of the county, north of the Sarnia area and southerly, east of the St. Clair River to an area near Walpole Island. The balance of Lambton County has no Cambrian sediments present. Consequently, with limited host or source Cambrian strata, the potential for Cambrian aquifer gas storage is limited.

The currently known Cambrian fields in Ontario are predominantly oil bearing. Some had gas caps of varying thicknesses above the oil leg. Pay sections in the North Willey Pool in Elgin County were 1,085 to 1,088 m (3,559 to 3,569 feet), the Gobles Pool in Oxford County, 891 to 907 (2,922 to 2,975 feet) and the Innerkip Pool in Oxford County, 873 to 890 m (2,863 to 2,919 feet). The cumulative production of gas up to and including 1982, of 64,355.4 10^3m^3 (2,300 MMcf) from the Innerkip Pool, was the largest gas volume produced to 1982 from known Cambrian pools(9).

The Electric Pool (abandoned) at a depth of 1,209-1,215 m (3,966 to 3,985 feet), and the Innerkip East Pool at a depth 868-879 m (2,847 to 2,883 feet) are the only two Cambrian pools reported to date, that contained only an accumulation of natural gas. Innerkip East Pool is still under initial gas production operations in Oxford County. Cumulative production, including 1982, for the Electric and Innerkip gas pools is reported by O.M.N.R. as 1,869.7 10^3m^3 (66 MMcf) and 2,351.2 10^3m^3 (84 MMcf), respectively(8).

The O.M.N.R. has concluded that as of December 31, 1981 the potential Cambrian gas reserves are approximately 6,271,000 10^3m^3 (224,000 MMcf) of which, 31% are estimated to lie in the Appalachian Basin portion of Ontario with the remainder being contained in the Michigan Basin. Approximately 75% of the reserves, or 4,726,000 10^3m^3, are on land(9).

Currently no known suitable large volume depleted dry gas reservoir is available for potential storage in the Cambrian.

The Cambrian sediments are judged to have little potential as underground gas storage reservoirs over the next ten years as no suitable formations are located close to existing compression facilities and markets. Aquifer storage potential in the Cambrian would have to be assessed by a special study to determine if potential

underground reservoirs exist in the Cambrian Formation which are safe and capable of successfully storing gas. With Cambrian sediments at depths of around 1,097 to 1,463 m (3,600 to 4,800 feet), well exploration and development drilling costs would be the highest of all potential storage horizons in the Southwestern Stratigraphic section.

4.4.4 ORDOVICIAN STORAGE

The Ordovician sediments are next highest in the southwestern Ontario stratigraphic column. As is the case with the Cambrian Formations, reservoirs discovered to date have had a predominance of oil accumulation. The only exception has been the Dover Field, in Dover Township, Kent County, which was discovered in 1917, and contained a large volume of gas and some oil.

As of December 31, 1982, the O.M.N.R. reported gas production from the Dover Ordovician Field of 364,004.5 10^3m^3 (13,000 MMcf) and oil production of 38,698.5 m^3 (1,366 Mcf), after 65 years of production. Some gas and oil are still being produced in the Dover Field in 1986.

The Dover Ordovician wells are at depths below surface of 890-938 metres (2,920-3,077 feet). With storage requirements to deliver the total working capacity in about 100 days, the Dover Field with lower initial flow rates is not considered a future potential storage pool.

The potential gas reserves as of December 31, 1981 in the Ordovician are estimated (by the O.M.N.R.) to be 9,702,800 10^3m^3 (347,000 MMcf), of which 30% are estimated to be in the Appalachian Basin portion of Ontario with the remainder being contained in the Michigan Basin portion of Ontario. About 59% of the reserves, or 5,686,000 10^3m^3 (201,000 MMcf) are on land(10) and is 203,000 MMcf greater reserves than the Cambrian at shallower depths.

Only additional drilling in the Ordovician will ultimately determine whether it is, like the Cambrian, more oil prone than gas, and thus devoid of dry natural gas reservoirs which could be used for future gas storage operations. Therefore, it seems very unlikely that within the next decade, Ordovician natural gas storage will be developed in Ontario. Aquifer storage has the next highest potential for storage when compared with the more economic pinnacle reef gas storage reservoirs. However, as discussed below, sufficient additional capacity exists in pinnacle reef reservoirs to satisfy storage requirements for the near future.

4.4.5 SALT CAVITY STORAGE

Salt cavity natural gas storage appears to have some potential in the long term in the Sarnia area and possibly the Windsor area. The "A_2" salt formation has a thickness of about 45.7 m (150 feet) near Sarnia. The "B" salt formation has maximum thickness of about 91.4 m (300 feet) near Sarnia and a thickness of 76.2 m (250 feet) around Windsor. In neighbouring Michigan, two storage facilities, one in each salt formation, are operated presently.

Due to the presence and thicknesses of the "B" and "A_2" salt formation in the Sarnia and Windsor areas salt cavern storage in Ontario for natural gas is placed at a higher level of potential than the preceding methods of storage. However, salt caverns have a lower level of potential when compared with the pinnacle reef formations developed during the Silurian Period. It should be noted that salt cavity storage in Ontario is extensively used in the storage of liquified petroleum gases with 66 active operating salt caverns in Ontario, 60 of which are located in Lambton County and six in Essex County near Windsor(8). Disposal of large quantities of brine produced in the creation of the salt caverns could be a problem.

4.4.6 DELTA PRESSURING CURRENT OPERATING NATURAL GAS STORAGE POOLS

Additional gas storage volume can be achieved in the storage pools by delta pressuring the pools to a higher pressure level than is the current operating practice. "Delta pressuring" is defined as an increase in the storage operating pressure over the gas discovery pressure. It is expressed in units of kPa (psi). The pressure gradient is calculated by dividing the reservoir maximum operating pressure by the depth from ground level to the crest of the reservoir and is stated in kPa/m (psi/ft).

Potential undeveloped working storage capacity currently exists in all Lambton County Silurian Guelph pinnacle reef pools. For instance, by delta pressuring all of the existing Union Gas pools to a 15.83 kPa/m (0.70 psi/ft) pressure gradient from the present 14.70 kPa/m (0.65 psi/ft) gradient as well as lowering the cushion levels to approximately 2,068 kPa (300 psia) an increase in working capacity from about 2,659,000 10^3m^3 (93,900 MMcf) to 3,300,000 10^3m^3 (115,100 MMcf) can be realized(11).

Recently conducted research into maximum allowable reservoir pressures (that is, before leakages occur through the caprock pores) has revealed that the anhydrite caprock over the pinnacle reef storage pools has an "extremely high threshold pressure"(12). The definition of "Threshold Displacement Pressure" is "...the minimum pressure difference between the gas pressure at the face of the caprock and the water phase pressure immediately above the gas-water interface within the caprock at which the gas starts to move continuously through it"(12).

As a result of this research, storage operators in Michigan and Ontario increased their operating reservoir gas storage pressures to higher delta pressures per foot of depth. For example, Michigan Consolidated Gas has gone to a delta pressure of 16.73 kPa/m (0.74

psi/ft) in the Belle River Mills natural gas storage pool in St. Clair County, Michigan and ANR Storage Company has delta pressured its Rapid River 35 reef pool to a pressure gradient of 16.28 kPa/m (0.72 psi/ft) of depth.

Union's current design standard calls for a future gradient of 16.96 kPa/m of depth (0.75 psi/ft).

4.4.7 SILURIAN PINNACLE REEF STORAGE

The highest priority for future potential natural gas storage within the next decade are depleted or near depleted gas Silurian Guelph pinnacle reef formations in Lambton County. (Depleted implies that the majority of the initial native gas in place has been removed and storage space is available.) There are currently seven pools of major interest in Lambton County (see Figure 4-6).

TABLE 4-1

Potential Storage Pools in Lambton County

Pool Name	Status of Pool
Enniskillen #28	Depleted, Inactive, Shut-in
Sombra	Depleted, Inactive, Shut-in
Oil Springs East	Depleted, Active, Producing
Mandaumin	Depleted, Inactive, Shut-in
Moore 3-21-XII	Depleted, Active Producing
Dawn 1-27-6	Not Depleted, Active Producing
Sarnia 1-8-A	Not Depleted, Active Producing

These pools are similar reef-type pinnacle pools to the 14 natural gas storage pools currently operated by Union and Tecumseh and are acknowledged to be the best and most economic storage available due to their reservoir characteristics.

There are many other Silurian gas fields in southwestern Ontario both on land and offshore, however, due to their reservoir characteristics and locations they are not considered economic for gas storage purposes. In Table 4-2, original gas reserve and production figures are presented as reported by the O.M.N.R. Petroleum Resources Section.

TABLE 4-2

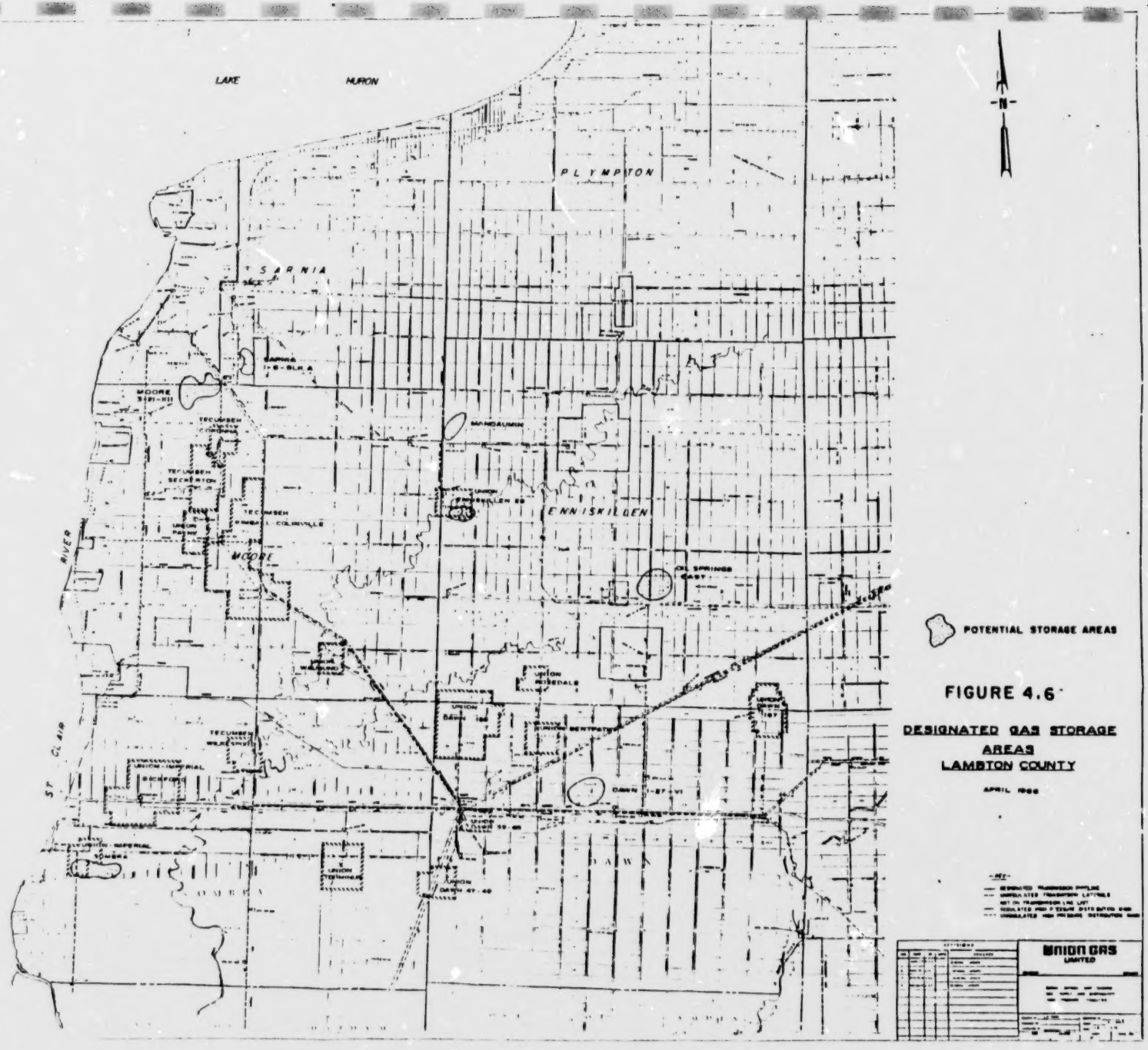
Original Gas Reserve and Production Figures

Pool Name	Cumulative Gas (Production as of 1985-12-31 10^3m^3	(MMcf)	Original Gas In Place 10^3m^3	(MMcf)	Original Pressure kPa(abs)	(psig)
Enniskillen #28	55,098.0	(1,968)	67,253.6	(2,402)	5,390	767
Sombra	54,558.1	(1,949)	73,528.0	*(2,626)	6,571	938
Oil Springs East	121,030.4	(4,323)	125,930.0	(4,497)	6,479	920
Mandaumin	54,049.9	(1,930)	58,396.4	(2,086)	4,872	692
Moore 3-21-XII	503,531.1	(17,983)	551,408.9	(19,693)	6,720	930
Dawn 1-27-6	15,562.4	(556)	126,000.0	**(4,500)	6,074	866
Sarnia 1-8-A	60,173.0	(2,149)	125,000.0	(4,464)	5,824	830

The location of these pools are shown in Figure 4-6.

* Imperial Oil reserve estimate (Bickford/Sombra rate hearing E.B.O. 375).

**Initial reserve estimates subject to future revision (first production in 1985).


LAKE HURON
PLYMPTON
SARNIA
MOORE
ENNISKILLEN
MOORE
ST. CLAIR RIVER
N
POTENTIAL STORAGE AREAS
FIGURE 4.6
DESIGNATED GAS STORAGE AREAS
LAMBTON COUNTY
APRIL 1988
UNION GAS LIMITED

4.5 SUMMARY

Of the fifteen operating underground gas storage reservoirs in Ontario fourteen are located in Silurian Guelph pinnacle reef pools in Lambton County. The other reservoir, in Welland County, is in the Whirlpool sandstone formation. The current combined working storage capacity of these pools is 4,146 $10^6 m^3$ (145.9 Bcf).

The potential for additional gas storage capacity is greatest through delta pressuring of existing storage reservoirs and the development of additional known pinnacle reef formations which are still producing hydrocarbons or are depleted and shut in (see Figure 4-7). It is anticipated that underground gas storage requirements over the next ten years can be met through these two means.

It is concluded that gas storage in other types of underground formations will not be economic or required within this time frame when compared to pinnacle reef alternatives.

FIGURE 4-7

Gas Storage Potential Working Capacity

Gas Storage

A total of 15 gas storage pools were in operation and three pools were inactive during 1982.

Total gas storage working capacity for 1982 was 5,351.6 10^6m^3.

Lambton County remained the centre for gas storage operations, containing all but one of the pools within its boundaries (Table 27).

TABLE 27. GAS STORAGE—SOUTHWESTERN ONTARIO.

RESERVOIR	ZONE	STATUS	OPERATOR	WORKING CAPACITY AT ORIGINAL RESERVOIR PRESSURE 10^6m^3	ORIGINAL RESERVOIR PRESSURE kPa	WORKING CAPACITY WHEN DELTA PRESSURED 10^6m^3	RESERVOIR PRESSURE WHEN DELTA PRESSURED kPa
Bentpath	G., A-1	Active	Union	111.0	5,978	158.1	8,508
Bickford	G., A-1	Active	Union	400.8	6,398	545.3	8,708
Corunna	G., A-1	Active	Tec.	99.1	6,502	150.7	9,887
Crowland	Whirlpool	Active	Cons.	11.3	3,447	14.2	4,330
Dawn 156	G., A-1	Active	Union	581.9	6,067	884.1	9,218
Dawn 167	G., A-1	Active	Union	141.6	6,247	201.1	8,867
Dawn 47-49	G., A-1	Active	Union	95.7	5,964	113.6	7,081
Dawn 59-85	G., A-1,A-2	Active	Union	113.6	5,964	138.5	7,267
Enniskillen 26	G	Inactive	Union	75.4	5,281	116.4	7,819
Kimball-Colinville	G., A-1	Active	Tec.	841.3	6,336	1,211.0	9,122
Payne	G., A-1	Active	Union	354.9	6,047	528.8	9,011
Rosedale	G., A-1	Active	Union	69.7	6,474	96.6	8,970
Seckerton	G., A-1	Active	Tec.	255.0	6,481	375.6	9,653
Sombra	G., A-1	Inactive	Union	51.0	6,474	74.8	9,473
Terminus	G., A-1	Active	Union	233.7	5,971	325.8	8,322
Waubuno	G., A-1	Active	Union	186.7	6,419	272.8	9,377
Wilkesport	G., A-1	Active	Tec.	165.4	6,378	N.A.	N.A.
Zone	A-1,A-2	Inactive	Union	101.9	4,971	146.1	7,129
TOTAL				3,890.0		5,353.5	

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PART 4
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PART 5

THE GAS SUPPLY/DELIVERY SYSTEM

5.1 INTRODUCTION

This section describes the natural gas supply and delivery system which provides gas service to Ontario. There is a considerable natural gas production infrastructure in place in Alberta which provides the gas supply to the Alberta-Saskatchewan border, the starting point of the TransCanada PipeLines transportation system. The gas supply system consists of gas wells and gas fields; gas gathering systems; and gas processing plants.

The natural gas delivery system consists of the Alberta Gas Transmission Facilities operated by NOVA, an Alberta Corporation (NOVA) and the following facilities outside Alberta:

Mainline Pipeline System (TransCanada)
Distribution System - Local Transmission
- Local Distribution
- Underground Storage
- Local Production

Each of the foregoing components is described in detail below to establish the role played by each in the development of the Ontario gas industry.

5.2 GAS WELLS AND GAS FIELDS

The large reserves of natural gas which supply most of Canada are found in what is referred to as the Western Sedimentary Basin. This geologic occurrence covers most of Alberta, southern Saskatchewan, southwestern Manitoba and northeastern British Columbia. The basin runs in a southeast to northwest direction across the Prairie Provinces into British Columbia and the Territories.

A considerable volume of natural gas is found in association with crude oil or condensates and is often contaminated with hydrogen sulphide and carbon dioxide. However, some of the smaller reserves of southern Alberta and Saskatchewan are dry and sweet.

Natural gas is found in many different formations in fields varying in size from one or two wells to fields having several hundred wells and covering many hectares. Recent estimates of remaining natural gas reserves in western Canada are in the order of 81 exajoules (2,177 $10^9 m^3$). This represents about 30 years supply at the current production rate of about 2.8 exajoules (75 $10^9 m^3$) per year. Reserve additions projected for the next twenty years would increase current reserves by another 45 exajoules (1,210 $10^9 m^3$) or an additional 16 years at current demand levels. These estimates are provided in the National Energy Board 1985 Annual Report.

In spite of the favorable reserves to production ratio, the decline of existing fields and the expected lower productivity of reserve additions as well as gas deliverability problems are expected to commence in the next decade and become serious by the year 2005. However some relief for this situation is expected from the gas reserves of the Arctic Islands and the Mackenzie Delta.

The frontier reserves in the Arctic Islands and Mackenzie Delta are currently estimated to be in the order of 16 exajoules (430 $10^9 m^3$). Projects presently under consideration involve the delivery of this gas through a difficult island-hopping pipeline from the Islands to the Mackenzie Delta to connect up with the existing NOVA gathering system in Alberta.

5.2.1 GAS GATHERING

At each wellhead a certain amount of gas conditioning takes place. As the gas reaches the surface it usually contains certain amounts of liquid hydrocarbons and water vapour. These must be removed before the wellhead pressure is reduced to safe and more easily handled pressures to prevent the formation of hydrates in the connecting piping. Separators and dehyrators located at the wellhead, remove the hydrocarbons and water vapour and reduce the dew point of the gas to an acceptable level. At this point the gas volume is metered. The gas from each well in a field is gathered by individual pipeline into a field gathering system for delivery to the gas processing plant. In most cases gas from several fields is brought together for treatment at a central processing plant.

5.2.2 GAS PROCESSING

The natural gas from many of the deeper and more prolific gas fields contain considerable amounts of hydrogen sulphide and carbon dioxide. These two components known as acid gases are very corrosive to pipelines and associated equipment. To remove these acid gases and to recover valuable LPG's or propane, butane and natural gasoline still entrained in the gas a gas processing plant is installed.

The field processing plant consists of four primary sections: desulphurization; dehydration; sulphur recovery; LPG and natural gasoline recovery.

Desulphurization removes the acid gases by subjecting the raw gas to a solvent which absorbs the two acid gases. The solvent is then reheated in a distillation tower where the two acid gases are driven off and the purified solvent is recirculated. The acid gases are fed into a sulphur recovery unit where the hydrogen sulphide is

converted into elemental sulphur and the carbon monoxide is usually vented to the atmosphere.

Further dehydration is necessary as a result of the desulphurization process which again saturates the gas with water vapour. Here as in the case of the wellhead unit a glycol or dry dessicant is employed.

LPG and natural gasoline recovery involves the cooling of the gas through expansion and refrigeration, the propane and butane are recovered first and the resulting gas stream is subjected to contact with a chilled lean oil which absorbs the natural gasoline and releases it on reheating. This process recovers about 70% of the propane, 90% of the butane and virtually all of the natural gasoline. The resulting gas stream is then about 91% methane, 7.5% ethane, 0.5% propane and butane, 0.5% nitrogen and 0.5% carbon dioxide.

5.3 GAS DELIVERY SYSTEM

At this stage the gas has been produced, gathered and processed and passes into NOVA's Alberta gas transmission system for final gathering and further processing.

5.3.1 ALBERTA GAS TRANSMISSION SYSTEM (NOVA)

Within Alberta, NOVA has developed a major gas gathering system to gather gas from all producing areas of the province into a trunkline system. Two interconnected systems exist: the Foothills section and the Plains section. Almost all gas leaving the province is carried through these two systems. NOVA, formerly known as Alberta Gas Trunk, commenced limited operation in 1956 to deliver gas to the

initial stage of the TransCanada system. Rapid and continuous expansion followed for many years to meet the requirement of the growing domestic and export market. At present the NOVA system consists of 13,500 kilometers of pipeline from 4" through 48". It operates 37 compressor stations and employs about 1,500 people.

Before the natural gas enters the TransCanada system at a point near Empress on the Alberta-Saskatchewan border, it is subjected to final processing. A straddle or deep-cut plant removes all of the remaining butane and almost all of the remaining propane and ethane. These plants utilize a turbo expander to achieve the extremely low temperatures required for this process. The propane and butane is moved by rail and pipeline to markets across Canada and into the United States and the ethane is transported by pipeline to a major ethylene plant near Red Deer, Alberta.

5.3.2 MAINLINE PIPELINE SYSTEM (TCPL)

TransCanada operates one of the world's longest pipelines. The pipeline starts at the Alberta-Saskatchewan border near Empress, Alberta and runs through Saskatchewan, Manitoba, Ontario and Quebec to Montreal.

Almost all gas used in Canada east of Alberta is carried through this system and the Great Lakes system described below. The only exception is gas produced in Saskatchewan and Ontario. From the Alberta border to Winnipeg, four complete lines exist with some portions of a fifth loop in existence adjacent to several compressor stations. From Winnipeg east through northern Ontario and on to Montreal two complete lines exist with some sections of a third loop.

Gas also flows south from Winnipeg to serve markets in the United States and eastern Canada. This line, known as the Great Lakes

Gas Transmission Company, is 50% owned by TransCanada and runs through the states of Minnesota, Wisconsin and Michigan. It connects with the northern system of TransCanada near Sarnia, Ontario. A branch from Great Lakes in northern Michigan serves Sault Ste Marie, Ontario.

A loop in the northeastern section of Ontario runs from North Bay to a point south of Ottawa where it ties into the Toronto-Montreal line, thus bypassing the southern Ontario market area.

The TransCanada system including all its loops consists of more than 10,600 kilometres of pipe with a maximum size of 1,219 millimetres. It takes approximately six days for the gas to travel from Alberta to Montreal at speeds of about 29 kilometres per hour. The maximum operating pressure carried is 6,895 kilopascals.

There are 49 compressor stations containing 169 units totalling 1,020,500 kilowatts of power. Three types of compressor power are used: reciprocating engines installed prior to 1960; industrial turbines introduced in 1960; and aircraft turbines introduced in 1964. The aircraft turbine units represent 63% of the system's total compression and are the most reliable and cost efficient of the units used.

5.4 DISTRIBUTION SYSTEM

The last major component of the delivery system from the wellhead to the end user is the distribution system. This system involves the transmission lines connecting TransCanada with the local gas utilities, the distribution networks found under the streets of most Ontario towns and cities, the underground storage pools and local Ontario gas production.

5.4.1 LOCAL TRANSMISSION

There are several transmission lines or laterals owned by the Ontario distributors and two owned by TransCanada. The major pipeline serving Ottawa and Hull and a smaller line serving Temiscaming are owned by TransCanada. The largest utility-owned transmission system is the Dawn to Trafalgar line owned by Union Gas. This line carries gas for Union's own local use as well gas to and from storage for Consumers' Gas, gas for TransCanada from Great Lakes and storage gas for Gaz Metropolitain, I.C.G. and the Kingston Public Utilities Commission. Union collects transportation charges for gas carried for others.

Other smaller transmission lines serve the areas from North Bay to beyond Sudbury and from Sault Ste Marie to Elliot Lake in northern Ontario.

5.4.2 LOCAL DISTRIBUTION

Almost all cities and and towns in Ontario are served with natural gas by one or another of the gas distributors. The following is a summary of the distributors and the areas served by each. A map provided at the end of Part 5 outlines the utility franchise areas.

.1 The Consumers' Gas Company Ltd.

The Consumers' service territory consists of three major operating areas. The largest is the Metropolitan Toronto area from Mississauga and Brampton on the west, to Bowmanville and Peterborough on the east and to Collingwood and Barrie on the north.

The second area is the Niagara Peninsula including St. Catharines, Niagara Falls, Niagara-on-the-Lake, Welland and Fort Erie. Finally the Ottawa area including Ottawa, Petawawa, Brockville and Hawkesbury is served by Consumers'.

.2 Union Gas Limited

The southwestern part of the province from Sarnia and Windsor in the west to Oakville in the east and north to Owen Sound and Meaford is the general area served by Union Gas.

.3 I.C.G. (Ontario) Utilities Ltd. (I.C.G.)

Formerly known as Northern & Central Gas Corporation, this company serves a large area of northern Ontario along and near the route of the TransCanada northern pipeline. Two distinct areas are served with one starting in the Manitoba-Ontario border including the town of Kenora and following the pipeline route through northern Ontario to Orillia. A branchline serves Sudbury and beyond to Espanola. In the same area I.C.G. serves Sault Ste Marie and the north shore of Lake Huron to Blind River and Elliot Lake.

In eastern Ontario I.C.G. serves the north shore of Lake Ontario and the St. Lawrence River from Port Hope to Cornwall with the exception of the cities of Brockville and Kingston.

In western Ontario I.C.G. serves the communities of Rainy River and Ft. Francis.

.4 The City of Kitchener

The City of Kitchener owns and operates a gas utility serving this southwestern Ontario city. The utility buys all its gas from Union.

.5 The City of Kingston - Public Utilities Commission

The City of Kingston operates a gas utility as a part of its combined Electric and Gas Public Utilities Commission. The Kingston P.U.C. purchases its gas directly from TransCanada.

.6 Natural Resources Gas Limited (NRG)

NRG serves portions of the counties of Elgin, Middlesex and Oxford and the Municipality of Haldimand-Norfolk. It buys most of its gas from Union, but obtains some gas from its own wells and purchases some gas from other producers.

5.4.3 UNDERGROUND STORAGE

Part 2 of this report gives a detailed account of the natural gas storage fields in Ontario.

At present there are three companies operating storage facilities in the province. These are: Union Gas; Tecumseh Gas Storage Limited; and Consumers' Gas.

The storage capacity of these facilities which are located in southwestern Ontario is:

	$10^6 m^3$
Union	2661.3
Tecumseh	1472.0
Consumers'	12.5
Total	4145.8

5.4.4 ONTARIO NATURAL GAS PRODUCTION

Union, Consumers', Pembina Resources and several other companies produce natural gas in Ontario. The majority of the production is from fields located offshore in Lake Erie, with the remainder from small onshore fields in southwestern Ontario.

Production from all Ontario fields amounted to 589.9 10^6m^3 in 1985 and 584.2 10^6m^3 in 1984.

Union purchases Synthetic Natural Gas (SNG) from Petrosar amounting to volumes of 242 10^6m^3 in 1985 and 254 10^6m^3 in 1984.

5.5 SUPPLY AND DEMAND CHARACTERISTICS

5.5.1 SUPPLY CHARACTERISTICS

The gas supply for all Ontario natural gas users comes from three sources:

TransCanada PipeLines Limited
Local Supply
Petrosar SNG

TransCanada PipeLines Limited
Description of Classes or Types of Service
(extract from National Energy Board)

.1 Contract Demand - CD

TransCanada agrees to sell to a Buyer, in a specified delivery area, up to a specific quantity of gas each day, which represents TransCanada's maximum daily obligation to deliver to Buyer. For the transportation of the gas Buyer must pay a fixed monthly demand charge for this service regardless of volumes actually taken and also a commodity charge related to the volume taken.

.2 Annual Contract Quantity - ACQ

TransCanada agrees to sell to a Buyer in the Eastern Rate Zone an annual quantity of gas designated as the Annual Contract Quantity. 40% of this annual quantity is scheduled for delivery in

the winter period and 60% in the summer period. Various curtailment rights are available to TransCanada. Transportation charges relate to the volume taken each month with provisions for an annual supplemental charge for volumes offered and not taken.

.3 Small General Service - SGS

TransCanada agrees to sell to a Buyer, in a specified delivery area, up to a specific quantity of gas each day which represents TransCanada's maximum daily obligation to deliver to Buyer. A Buyer must pay a transportation charge related to the volume taken. Such service is available for a Buyer with primarily residential and commercial space heating load customers.

.4 Authorized Overrun Interruptible - AOI

TransCanada sells to a Buyer quantities of gas in excess of quantities contracted for by Buyer and which TransCanada may have available from time to time for delivery to a Buyer. Buyer must pay a transportation charge related to the volume taken.

.5 Peaking Service - PS

TransCanada agrees to sell to a Buyer a designated volume during the winter period in addition to gas purchased by a Buyer from TransCanada under TransCanada's CD Service Contract. Buyer must pay a transportation charge related to the volume taken. Volumes contracted must be taken or paid for if not taken.

.6 Temporary Winter Service - TWS

TransCanada agrees to sell to a Buyer a designated volume subject to curtailment provisions during the winter period in addition to gas purchased by a Buyer from TransCanada under TransCanada's CD Service Contract. Buyer must pay a transportation charge related to

the volume taken. Volumes contracted must be taken or paid for if not taken.

.7 T-Service

The tolls paid by the customer for T-Service are designed on a zone basis. Buyer has arranged to have certain volumes of gas delivered to TransCanada at the point where the facilities of NOVA join the facilities of TransCanada, and to have TransCanada transport such volumes to Buyer's market. Buyer must pay a fixed monthly demand charge for this service regardless of volumes actually taken and also a charge related to the volume taken.

.8 Storage Transportation Service - STS

A Buyer desires to have volumes of gas delivered into Union's storage at Lisgar and/or Dawn, Ontario during the summer period, and requires TransCanada to transport the withdrawal of storage gas during the winter period to market. A Buyer must pay a fixed monthly demand charge for this service and also a commodity charge related to the volume of gas delivered into storage.

.9 Transportation

The tolls paid by the customer for transportation service are designed on a point to point basis. TransCanada transports gas for a customer from specific receipt points to specific delivery points. Customer must pay a fixed monthly demand charge, regardless of volumes actually transported, and a commodity charge related to the volume transported.

.10 Interruptible Transportation Service - IT

An interruptible transportation service provided by TCPL for gas which is owned by another shipper. IT-Service has the lowest priority of services offered by TCPL. The shipper must pay a transportation charge related to the volume taken.

.11 Short-Term Contract Demand - SCD

A short-term firm sales service equivalent to Contract Demand Service but available for a period of one to three years.

.12 Short-Term Transportation Service - STT

A short-term firm transportation service equivalent to T-Service but available for a period of one to three years.

.13 T-AOI Service - T-AOI

An interruptible transportation service provided by TCPL for gas which is owned by another shipper. This is an overrun service available only after daily contractual obligations for T-Service have been fulfilled. The shipper must pay a transportation charge related to the volume taken.

The natural gas distributors in Ontario utilize the following types of service available from TransCanada:

1. Contract Demand - CD
2. Annual Contract Quantity - ACQ
3. Authorized Overrun Interruptible - AOI
4. Peaking Service - PS
5. Temporary Winter Service - TWS
6. T-Service
7. Storage Transportation Service - STS

The basic gas supply contract between TransCanada and the Ontario distributors is the Contract Demand or CD contract. This contract is in effect a take or pay contract since it contains a fixed monthly demand component, which is paid year round regardless of volumes actually used, and a commodity component directly related to monthly volumes used.

The demand component compensates TransCanada for the fixed charges for the pipeline capacity dedicated to the distributor. The commodity component pays for the actual cost of gas and the variable costs incurred to move the gas to the distributors point of acceptance.

It is with reference to this type of contract that the distributors load factor becomes important. Load factor is defined as the ratio of average day demand to peak demand expressed as a percent. This is shown as:

$$\text{Load Factor} = \frac{\text{Average Day}}{\text{Peak Day}} \times 100$$

It follows that the lower the peak day is in respect to the average day the higher the load factor is and the lower the average cost of gas. The lowest unit cost of gas occurs when the peak day and the average day are the same with a load factor of 100%.

There are several ways by which a gas distributor can increase its load factor. They include:

Interruptible sales
LNG peak shaving
LPG air peak shaving
Underground storage
TransCanada peaking service
TransCanada temporary winter service

The Ontario distributors make use of many of the above methods to achieve the best balance between winter peaks and summer lows.

Both Consumers' and Union utilize a combination of underground storage and ACQ gas from TransCanada as their principal method of load balancing. ACQ permits 60% of a contracted annual volume to be purchased in the summer period when gas is being put into storage and 40% of the annual volume to be purchased in the winter period to augment normal CD and storage withdrawal volumes at times of winter peaks. Both companies have considerable interruptible industrial and commercial sales which can be curtailed or fully interrupted during peak demand periods. TransCanada Peaking and Temporary Winter Service are used by both Consumers' and Union.

I.C.G. (Ontario) makes limited use of Union's underground storage and relies primarily on a L.N.G. peak shaving plant and a large percentage of interruptible industrial customers. Once again TransCanada's Peaking and Temporary Winter Service are utilized to obtain the maximum possible load factor.

Kingston P.U.C. contracts for a small amount of underground storage from Union and relies on TransCanada's services to optimize its gas purchasing.

The smaller utilities either purchase their gas supply from Union and Consumers' or from local sources and do not enter into load balancing or peak shaving to any great extent.

5.5.2 DEMAND CHARACTERISTICS

Preliminary statistics for 1985 prepared by The Ontario Natural Gas Association indicate the following:

Ontario Natural Gas - Final Demand

	$(10^6 m^3)$	
Residential	5673	29%
Commercial	5073	26%
Industrial	8859	45%
Total	19605	100%

Source: Ontario Natural Gas Association statistics.

The above table is based on provincial totals. The distribution of annual volumes by customer class varies widely among the companies.

Based on historical data, the average annual load factors for each customer class are generally assumed by analysts to be:

Residential	30%
Commercial	35%
Industrial	60%

Industrial includes a mix of all types of industrial customers; firm and interruptible; as well as space heating and high load factor process customers.

The following table indicates peak and average day demands provided by Ontario distributors in 1984.

1984 Peak and Average Day Volumes
($10^6 m^3$)

Company	Peak Day	Average Day	Load Factor
Consumers'	56.0	25.2	45%
Kingston P.U.C.	0.54	.26	48%
Kitchener	1.2	0.59	49%
I.C.G. (Ft. Francis)	0.46	0.23	50%
I.C.G. (Ontario)	15.5	8.35	54%
N.R.G. (Aylmer)	0.06	0.24	39%
Union	40.0	19.7	49%

SOURCE: Canadian Gas Association, Directory of Utility, Transmission and Production Companies for 1985.

The total of the above peak day figures indicates the non-coincident peak day volume and the load factors that would result on the TransCanada system if no peak shaving or underground storage were employed.

Assuming that the peak flow rate of gas from storage currently available is used on the peak demand day and using the average day volumes developed above, the distributor purchase load factors can be calculated. These load factors represent the apparent ratios on the supply system which are possible due to the peaking capability of storage.

1984 Equivalent Load Factors
($10^6 m^3$)

Company	Peak Day	Storage[1]	Purchase Peak	Purchase Load Factor[2]
Consumers'	56.0	36.0	20.0	126%
Union	40.0	26.1	13.9	142%
I.C.G. (Ontario)	15.5	3.5[3]	12.0	70%
Kingston P.U.C.	0.54	0.07	0.47	55%

NOTES: (1) Estimated peak day storage withdrawals based on information filed with the OEB.
(2) Purchases on peak day divided by average daily volumes.
(3) Includes LNG peak shaving.

It can be seen that the availability of underground storage as a source of supply on peak winter days has a remarkable effect on the load factors and therefore the cost of gas for the two major distributors and some significant benefit for the other utilities which make more limited use of storage facilities.

5.6 THE ROLE OF UNDERGROUND STORAGE

The importance of the availability of underground natural gas storage in southwestern Ontario cannot be over estimated. Without the ability to inject large volumes of gas into storage in the low consumption summer months for withdrawal during the peak consumption winter period, it is doubtful that natural gas could be delivered to Ontario at the competitive prices that have allowed gas to achieve the wide acceptance it now enjoys. Without the availability of the depleted gas fields of southwestern Ontario for seasonal load levelling the pipeline system would certainly have been built differently if indeed such a line could have been justified at all.

The potential for substantial underground storage, the strong industrial fuel market, large population, sizeable shut-in gas reserves in Western Canada and the opportunity for export sales to the north-central and northeastern United States all combined to provide the essential elements to make the Canadian pipelines feasible. While all elements made their contribution it is likely that the potential of underground storage located so close to the central Canada industrial market was one of the most important.

It is likely that if the pipeline had been built in the absence of economical seasonal storage the entire gas market would be quite different from what currently exists. It would have to rely more heavily on interruptible industrial contracts in order to balance

the variation in loads between winter and summer markets. A much greater differential would be required between firm and interruptible rates than now exists, in order to provide an incentive for more industrial customers to install dual fuel equipment necessary for interruptible service. The residential non-space heating load would also have been pursued more aggressively.

As shown in Section 5.5.2, the annual load factor of the Ontario market is in the range of 39% and 54%. This means that the peak day is just about double the average day. With the utilization of underground storage and a small assist from LNG peak shaving the purchase gas load factor increases dramatically from 55 to 142% for those companies employing storage.

In Ontario the total amount of underground storage used in 1985 is approximately 4,100 10^6m^3 compared to total Ontario sales of about 19,600 10^6m^3 indicating that approximately one fifth of all gas sold in the province goes into and out of underground storage.

Underground storage also provides a degree of emergency protection for Ontario customers in case of pipeline interruptions. This is covered in more detail in Part 7 - Emergency Storage Capability.

5.6.1 THE UNION GAS TRANSPORTATION SYSTEM

The Dawn to Trafalgar transmission pipeline plays a major role in storage operations in Ontario. The western terminus of the line at Dawn, in the Sarnia area, is a strategic point in the gas supply system for Ontario. At this point, gas is received from TransCanada through the Great Lakes pipeline system for delivery to Union, Tecumseh and Consumers'. Also at this point gas is received by

Union for storage in the Dawn and other storage fields, for delivery to Consumers', I.C.G. (Ontario), Kingston P.U.C. and Gaz Metropolitain. Also at this point Union takes delivery of transportation gas for Consumers' and TransCanada for delivery at the Lisgar/Trafalgar station near Toronto.

Withdrawals of gas from both the Union storage and the Tecumseh storage are gathered at the Dawn compressor station and injected into the pipeline system for delivery to Union customers along the pipeline route in addition to deliveries at Lisgar/Trafalgar.

In the early 1950's the present storage/transportation system began to take shape. The Dawn pools were formally designated for storage in 1950 and put into service in 1954. In 1957 the delivery system between Dawn and Trafalgar was working in both directions, providing gas for storage in the summer and from storage in the winter. In 1958 Union reached an agreement with Consumers' to store gas for Consumers' in the Dawn field. The agreement was for 7.5 billion cubic feet (212.5 $10^6 m^3$) over a 20 year period. With the signing of the Union-Consumers' agreement, looping of the original 26 inch (66 cm) diameter line was commenced with 34 inch (86 cm) pipe.

With completion of the Great Lakes system south of Lake Superior, which re-enters Canada at a point near Sarnia, the storage system took on a much more important role. Gas for summer injection now flowed through the much shorter U.S. route and the Dawn-Trafalgar line connected the two TransCanada delivery systems.

In the early 1960's, Consumers' and Imperial Oil Limited formed a partnership whereby each obtained a 50% interest in some leases held by Imperial in southwestern Ontario. The leases covered some of the depleted gas fields in the general Dawn area. This joint

venture became known as Tecumseh Gas Storage Limited. In 1964, Tecumseh entered service and was connected to the Dawn-Trafalgar pipeline system. The 34 inch (86 cm) loop was completed to carry gas to Union's developing franchise area and to transport gas for Consumers' and TransCanada. Later additional transportation contracts were signed with Gaz Metropolitain, Northern and Central and Kingston P.U.C. In the 1970's, Union commenced further looping of the system, this time using 42 inch (107 cm) pipe.

The system now consists of two complete lines: one being 26 inch (66 cm) and the other 34 inch (86 cm). The 42 inch (107 cm) looping now covers about 60% of the 228 kilometres between Dawn and Trafalgar.

In addition to the 57,420 KW (78,000 HP) compression station at Dawn, three compressor stations are operated on the pipeline system. At Lobo, near London, 26,100 KW (35,000 HP) are installed consisting of two turbine/centrifugal units. At Bright, near Woodstock, 29,800 KW (40,000 HP) are installed consisting of two larger units. At the eastern terminus the Trafalgar compressor station contains seven integral reciprocating units totalling 5,700 KW (7,600 HP) capacity.

The pipeline carried 67,326 10^3m^3 on the peak day of the 1984/85 heating season, of which 27,696 10^3m^3 was for Union's sales along the line and the remaining 39,630 10^3m^3 was delivered at Trafalgar to TransCanada, Consumers' and the other storage/transportation customers.

The peak day requirements on the Trafalgar line for the 1986/87 heating season is expected to be 68,387 10^3m^3.

5.7 SUMMARY AND CONCLUSIONS

The Ontario natural gas market is supplied by a large and complex delivery system starting at the wellhead and ending with the distributor.

The system consists of thousands of gaswells, hundreds of gas processing plants and almost 25,000 kilometres of large diameter gathering and transmission pipelines.

The number of people employed directly or indirectly by the gas industry supplying Ontario and the rest of eastern Canada has been estimated to be in the hundreds of thousands. This estimate is based on Canadian Gas Association (CGA) direct employment figures and assumed indirect employment multipliers applicable to the gas industry.

Almost all populated parts of Ontario are served with natural gas. Only parts of northern Ontario and the northeast shore of Lake Huron are not presently serviced.

At the current rate of use the proven reserves are adequate for about 30 years. Reserves additions anticipated over the next 20 years should add another 16 years to the life of western Canadian supplies.

The completion of pipelines to connect Arctic Islands and Mackenzie Delta reserves to the existing delivery system will enhance the conventional supply life by several decades.

PART 6

COST ALLOCATION AND RATE ANALYSIS

6.1 INTRODUCTION

The following sections describe the gas storage operations of Union and Tecumseh (Consumers') from the viewpoint of cost allocation and rate making. The current procedures followed by the companies are outlined based on recent rate filings with the Ontario Energy Board (OEB). The outline begins with current storage capacity and projected usage requirements developing into operating and maintenance expenses and investment or rate base considerations. Finally, the costs are allocated to the various customer classes which benefit from the storage service and unit costs of storage are calculated. This gives the costs of storage which are currently included in the rates of the distribution utilities, since storage costs are passed directly through to utility cost of service.

At this point various alternatives to the existing storage process are introduced and discussed. In developing the alternatives, the assumption is made that the present storage facilities do not exist and all transportation service must be provided on a current load basis. This is somewhat analogous to the electric power industry, where no economical means of storage exists and production/transmission levels must follow the load requirements of the system. In the case of the Canadian natural gas industry, the transportation distance is significantly greater than that for electrical systems. However, it might be expected that a gas delivery system without storage near major load centres would experience similar load factors and planning criteria/requirements. These and other considerations are evaluated in more detail in Section 6.4.

As part of the evaluation of alternatives, the TransCanada rate structures are also analysed, in particular the derivation of Contract Demand (CD) and Annual Contract Quantity (ACQ) rates for the Ontario region. Without storage facilities the ACQ service would not

be available and all contracted annual volumes would have to be supplied under a CD type of rate.

6.2 THE COST ALLOCATION PROCESS

For regulated utilities there are well established procedures which are used to allocate all utility costs of service to the appropriate customer classes. In the case of utilities providing a gas storage function costs are developed and separated from the other utility services in order that specific rates to be charged for storage can be determined. In the following sections the allocation procedures of Union and Consumers' (Tecumseh) are described (from documents filed before the OEB) in order that the various components of the resulting rates can be identified. This information can then be used in the later analysis of rates without storage.

6.2.1 UNION GAS LIMITED

Union operates an integrated gas delivery system both from the manner of receipt and physical movement of gas and also from a functional standpoint. Union's operations involve all the functions prevalent in the industry, namely: exploration, production, purchase, storage, transmission and distribution. Portions of the cost of all these functions apply to most categories of sales customers. These categories include residential, commercial and industrial customers. The type of service, such as firm, interruptible or seasonal, varies within these categories, as does the sales load factor. The sales rates reflect the different services provided.

This necessitates detailed analysis in order to determine the cost levels for each component of service.

In addition to retail sales, Union also provides specialized services involving only certain functions. Examples in this regard are:

(1) Union operates small diameter pipelines from production fields to its main transmission system or storage pools for transport of its own production and also for that of Consumers' Gas. The facilities required for this service are specific pipelines and measurement equipment.

(2) Union provides storage and transportation on its main transmission system for other utilities, including Northern and Central Gas and Gaz Metropolitain.

(3) Union transports gas for TransCanada PipeLines on the main Dawn/Trafalgar pipeline system.

(4) Union sells gas to the City of Kitchener gas utility, and to other small utilities, on a wholesale basis.

An important consideration in the design of rates for sales customers and for the above specialized services is the level of costs attributable thereto.

Cost is not the only factor recognized in the development of unit rates but it is an important input to the rate designer. Other factors taken into account are rate stability and fairness (non-discriminatory) aspects. Unit costs are used as a guide and provide information on trends in cost responsibility. The multiple functions involved in Union's operation creates a need for a very detailed and fully distributed cost study.

Union's approach to the cost of service study involves three basic steps:

1. Functionalization
2. Classification
3. Allocation of costs to rate classes.

Under Functionalization, Union recognizes four distinguishable activities necessary to acquire and move gas to market. These are:

Purchase and production of gas;
Storage;
Transmission; and
Distribution.

The accounts of the company show the direct costs of these functions, both for plant investment and operating and maintenance expenses, in accordance with the Ontario Energy Board System of Accounts.

Functional costs are then classified according to cost incurrence. For Union these are:

Commodity;
Capacity; and
Customer.

The allocation process involves determination of appropriate units of use for each sales classification. The relationship of units for each class component to the total system determines the share of cost assignment.

In Appendix III financial schedules submitted before the OEB by Union Gas for the cost allocation process are reviewed. These schedules are extracted from documents filed by Union in December 1985 in support of its rate application under EBRO 405-2 before the Ontario Energy Board and are based on forecast activity for the test year ending March 11, 1987.

The final result of the cost analysis is the comparison of allocated costs with projected revenue for each rate class. This comparison is provided on Exhibit K2.1 in Appendix III. The revenue excess or deficiency represents the difference between cost for the 1987 test year and revenue resulting from rates in effect in December 1985, before the awarding of any increase under the rate application.

The total requested increase in revenue for fiscal year 1987 is $53.3 million. Of this increased revenue requirement, General Service represents the major portion with Residential Service revenue being deficient by $30.7 million, and Non-contract Commercial and Industrial revenue by $10.8 million. These differences are the result of the numerous estimates and judgments made in the cost allocation study. They are thus used as guides in making changes to existing rates in order to recover the projected revenue deficiency.

Storage and Transmission Operations

Also in Appendix III the separate cost study for storage and transportation costs is reviewed. A significant portion of these costs relate to facilities required for service to other utilities, such as Consumers' Gas, Northern & Central Gas, and TransCanada PipeLines. Union determines rates for these services based on cost. This requires a separate cost study for storage and transportation services.

From an analysis of Union's exhibits unit storage costs for the different utility customers have been calculated. Unit costs vary because of the difference in usage patterns among Union's sales customers and storage customers. For the utilities receiving storage under Rate Schedule M12, a three part rate structure is used.

The rate for "Space" applies to the total storage capacity required by the user. The "Demand" category recognizes the peak day

withdrawal requirement and this is a function of the number of days of withdrawal during the winter period. The "Commodity" rate is applied to volumes moved into and out of storage. As the storage profile for each utility differs, so will the average costs.

Unit storage costs for Union, and for other utilities contracting for storage service, are provided on Table 6-1, both in million cubic metres and thousand cubic feet.

On Table 6-2 the distribution of fixed storage costs to Union's sales customers by rate schedule is shown.

Also included as supporting data are excerpts from a summary prepared annually by H. Zinder & Associates of Washington, D.C. on United States storage rate schedules which are subject to regulation by the Federal Energy Regulatory Commission (see Appendix IV). The rate structure and level of rates vary for each utility due to the difference in investment, operation and types of service offered. For these reasons comparison of rates is difficult. Determination of average rates requires assumptions on peak day, seasonal and annual volumes.

6.2.2 THE CONSUMERS' GAS COMPANY LTD.

Gas storage operations for Consumers' comprise wholly-owned facilities, a fifty percent ownership in Tecumseh Gas Storage Limited and contracted storage with Union Gas.

Exhibits filed by Consumers' in March, 1985 in E.B.R.O. 403 for test year ended September 30, 1986 include particulars of its storage operation. References to exhibits follow the code used by Consumers'. These exhibits are reviewed in Appendix V.

TABLE 6-1

Union Gas Limited
Forecast Year Ended March 31, 1987
Allocated Storage Costs

	Cost ($000)	Allocation Units ($10^6 m^3$)	Unit Cost ($/$10^3 m^3$)	($/Mcf)
Average Cost of Union Gas Storage for Other Utilities				
Consumers' Gas	5,065	720.3	7.032	.1992
Gaz Metropolitan	1,886	550.1	3.429	.0971
Northern & Central	808	200.0	4.04	.1145
Kingston P.U.C.	56	14.0	4.00	.1133
Total storage under Rate 12	7,815	1,484.4	5.265	.149
Other storage services	2,249	-	-	-
Total to other utilities	10,064	1,484.4	6.780	.192
Balance for Union Sales Customers				
Share of allocated costs (U)	14,454	567.8	25.456	.721
Sub-total	24,518	2,052.2	11.947	.338
Space costs directly for Union (U)	23,245	567.8	40.939	1.160
Total	47,763	2,052.2	23.274	.659
Total Union customers (U)	37,699	567.8	66.395	1.881

TABLE 6-2

Allocation of Storage Fixed Costs to Union
Sales Classification(1)
March 31, 1987
($000)

	Rate Schedule	Fixed Storage Costs			Annual Sales Volume (10^3m^3)
		Space	Deliver-ability	Total	
Costs allocated to:					
Firm Sales					
General Service	M2				
Residential		8,417	3,676	12,093	1,486
Non-contract comm. and industrial		8,511	3,684	12,195	1,817
Sub-total		16,928	7,360	24,288	3,303
Firm indust. and comm.	M4	355	139	494	503
Spec. Large Volume, firm	M7	879	350	1,229	1,410
Large wholesale	M9	919	350	1,269	234
Small wholesale	M10	8	4	12	1
Non-Firm Sales					
Interruptible and Commercial	M5A	1,395	170	1,565	703
Special Commercial Large Volume	M7	790	164	954	1,168
TOTAL		21,274	8,537	29,811	7,330

NOTE: (1) After costs have been assigned to storage and transportation customers.

The major storage investment included in rate base is the average value of gas in storage. For the test year the balance is estimated at $177.5 million.

Also included in rate base is Consumers' 50% interest in the common shares of Tecumseh Gas Storage. Consumers' share of the common equity of Tecumseh is $12.1 million for the test year.

The approximate impact of Consumers' storage operation on cost of service is as follows:

	$ Millions
Operations and maintenance	.1
Rate base	
Net plant investment	1.5
Gas in storage(1)	177.5
Total	179.0
Return allowed, 12.59%	22.5
Income taxes, at 51% rate	
(1 - .49/.49) x Return	23.4
Total cost of service	46.0

This calculation includes available direct costs only; no allocations are made for administrative and general costs. Property taxes are not readily available and not included, since they are not considered significant.

(1) Includes gas in Tecumseh and Union storage which is owned by Consumers'.

Based on the above forecast figures, the unit storage costs excluding gas investment costs are as follows:

Tecumseh	$\$8.32/10^3m^3$
Union	$\$13.42/10^3m^3$
Consumers'	$\$13.35/10^3m^3$

The overall average cost of storage to Consumers' is $\$31.26/10^3m^3$, including the inventory cost of gas stored.

6.3 GAS TRANSMISSION COSTS

As part of the analysis of existing rate structures and cost allocation procedures, the costs of transporting the gas volumes begins with a general description of the transmission operations related to Ontario storage leading to a development of the current unit costs of the various transmission services provided.

6.3.1 TRANSCANADA PIPELINES

The cost allocation methodology employed by TransCanada in determining transportation tolls is also analysed in order to provide a framework for costing several of the alternatives to the existing gas storage operations. Details of the determination are given in Appendix VI.

Unit costs and volume/distance unit costs are summarized below for use in comparisons with derived unit costs for a re-designed gas transportation system.

Cost per 10^3m^3 - kilometer	$.014085
Cost to Dawn station	$36.804/10^3m^3$
Cost to Sheridan (Lisgar) station	$42.325/10^3m^3$

6.3.2 UNION GAS

The transmission system operated by Union consists of main compression facilities at Dawn, near Sarnia, and pipeline plus additional line compression facilities from Dawn through to Trafalgar, near Oakville. Tie-ins to the TransCanada system are at Dawn and Trafalgar (Lisgar). The pipeline consists of three parallel lines; the original 26" line constructed about 1958, a 34" line added in the 1960's, and a 42" line which has been installed in annual sections of about 15 kilometres and is now approximately 60% complete. A more detailed description can be found in Part 5.

The development of rate base and revenue requirement for transmission related plant is summarized in Appendix III.

6.4 ANALYSIS OF THE BENEFITS OF STORAGE

The terms of reference for this study specify that an analysis of the benefits of gas storage to each of the elements of the gas supply, transportation and distribution process will be carried out. The approach specified is to compare current retail rates with those resulting from a revised system which does not have underground storage. The following elements of the system are to be considered:

1. the landowner
2. the storage company
3. Ontario distributors

4. distributors and other customers east of Ontario
5. TCPL
6. export customers of TCPL
7. natural gas producers in Alberta
8. NOVA
9. residential consumers in Ontario
10. interruptible industrial consumers in Ontario
11. firm industrial consumers in Ontario

This part of the report develops rates from the analysis in Section 6.2 of the current cost allocation procedures followed in the determination of transportation, distribution and storage rates. This gives a basis for the current rates and the adjustments required for the revised system without storage.

The next section discusses alternative evaluation methods, leading to the section which outlines the hypothetical gas system without storage and provides an analysis of the costs and resulting changes in rates. The impact on the various elements above is then discussed.

6.4.1 ALTERNATIVE ANALYSIS METHODS

One way of analysing the benefits provided by the gas storage facilities in southwestern Ontario is to develop a hypothetical gas delivery system which assumes no storage is available and determine the resulting costs to the various elements of the system. There are a number of problems with this type of analysis. The first is that there can be no firm basis for establishing how the gas system would have developed in the absence of storage, or for that matter whether the system would have developed at all. Without the economies provided by a high load factor, the extreme length from the source to the major markets would most likely have dictated an entirely

different market development. It is conceivable that only the large volume, high load factor customers could have been considered when developing the gas markets. Seasonal rate premiums, if based on cost causality (i.e. fully allocated cost of service), would have been such as to severely restrict the development of the seasonal load sector of the market. Price competition from other energy sources would have meant that, in the absence of government price subsidies, the low load factor gas market (space heating) would be small fraction of what it is today.

In addition, gas exports from Eastern Canada would not have been competitive in other than high load factor cases.

It is also conceivable that other types of gas storage would have been developed more extensively as they have been in the United States. These would have included LNG facilities and propane injection systems which are considered generally economic only for short periods of deliverability or "needle peak" requirements.

The resulting gas supply and market situation could thus have developed without seasonal storage into a scaled-down version of the high load factor system that it currently is. This would logically lead to the conclusion that the overall "CD" type of rates would be not markedly different from those currently in place, with the only differences due to economies of scale.

Since the differential between CD and ACQ service rates is based on the costs of providing storage for the ACQ volumes, there would be no direct net benefit imputed to the existing storage facilities. An explanation and derivation of the CD-ACQ differential is given in Appendix VI.

This conceptual development of the gas markets and delivery system could be assumed to represent one end of a range of development possibilities.

A second method of valuing the benefits of underground gas storage, one which has been filed before the OEB but not yet considered by the Board, assumes that if seasonal storage were not available all ACQ volumes received by Union and Consumers' would have to be supplied under existing CD rates. What is not considered is how the TransCanada system (including the Great Lakes line) would manage to accommodate the peak day requirements of the market. Since the TransCanada system is now operating at over a 90% annual capacity factor there would be a significant requirement for increased throughput capability. In addition, the utilization factor of the pipeline would be significantly reduced, causing operating efficiency to be reduced. The result of these changes would be additional fixed charges and operating costs which would flow through the cost allocation process as higher transportation rates, since volume throughput would not change.

By ignoring the impact of changes in the volume delivery pattern and consequent increased transportation facilities, this method of analysis is not complete in its determination of the benefits of gas storage to the gas system.

6.4.2 SYSTEM COSTS WITHOUT STORAGE

A common methodology used for establishing the benefits provided by a particular development is to examine the costs involved in providing the same service or facility through the next best alternative. Since the gas transmission and delivery system evolved on the basis of seasonal gas storage being available there is no simple way to hypothesize an alternative system which might have developed without this type of storage available. Any significant increases in

transportation and delivery costs would have meant a loss of market share to competing fuels. This in turn would have dictated a different evolution of the natural gas system without considering the possible changes in government policy regarding natural gas development.

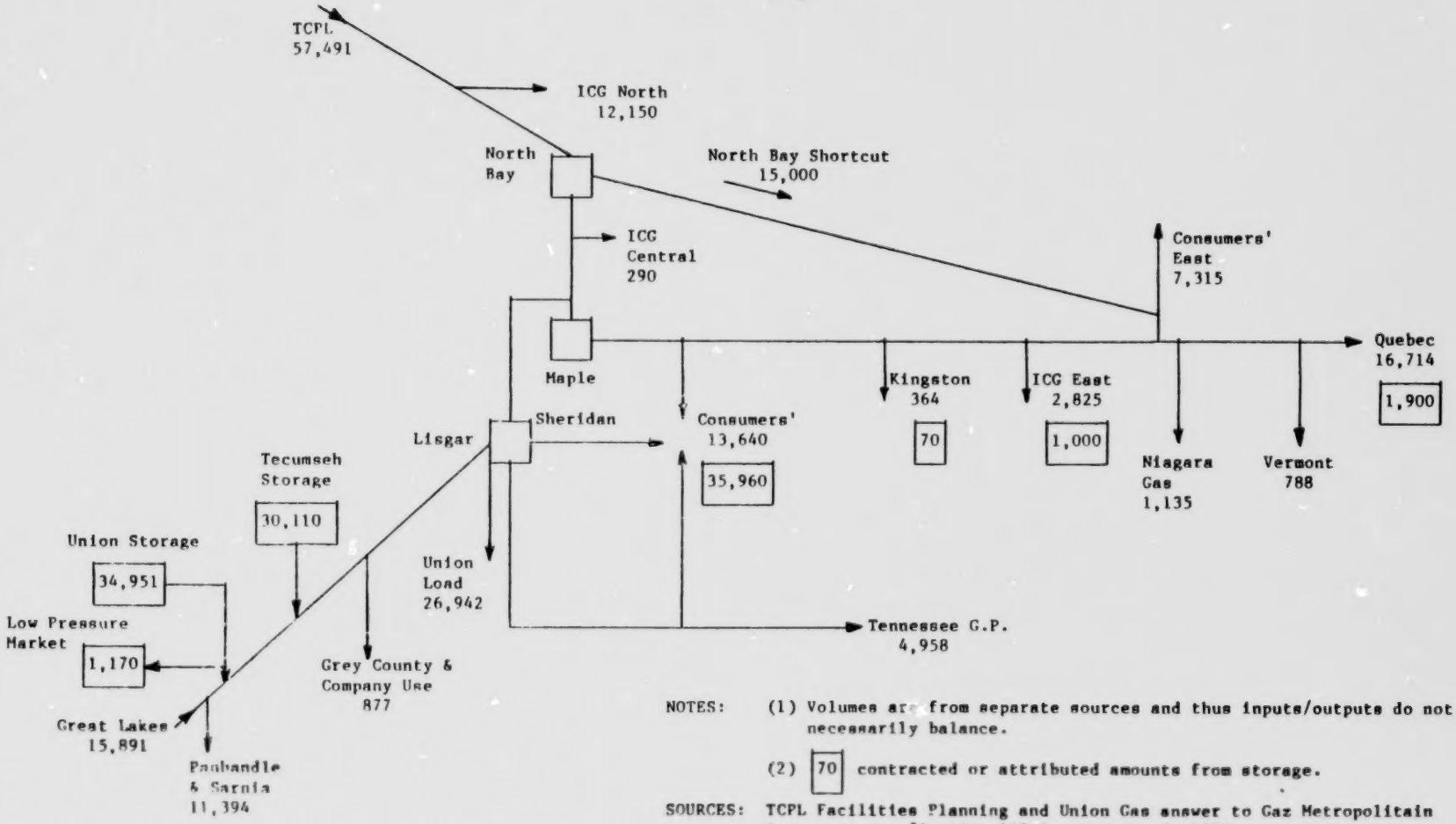
In the following analysis an attempt is made to estimate the current state of a natural gas delivery system which would have developed, in the absense of seasonal storage capability, to serve the existing monthly load pattern of the domestic market.

This requires a pipeline system which would be capable of meeting the additional peak day volumes which are currently being provided from underground storage. For the analysis the planned peak day volumes for the 1986-87 winter season are used. In order to determine the additional requirements on the TransCanada system (it is assumed that distribution utility systems are not affected since they already are designed to meet peak requirements) a graphical representation of peak day flows is presented in Figure 6-1. From this figure it is evident that a total of 65,060 10^3m^3 is planned to be withdrawn from Union and Tecumseh storage over the winter peak day. When this figure is added to the 1986-87 total peak day requirement of the TCPL central delivery system, the total market volume is 135,205 10^3m^3 per day. From the recent TCPL export facilities filing the peak day throughput capability of the combined TCPL and Great Lakes system is 78,600 10^3m^3 (see Table 6-3). If it is assumed that all existing and projected firm loads (including exports) would be met by the augmented system, the additional peak day throughput capability would have to be:

$$\begin{array}{rl} & 135{,}205\ 10^3m^3/d \\ - & \underline{78{,}600} \\ & \underline{56{,}605}\ 10^3m^3/d \end{array}$$

FIGURE 6-1

Peak Day Design Volumes 1986-87
Ontario Gas Transmission System
10^3m^3/day



NOTES: (1) Volumes are from separate sources and thus inputs/outputs do not necessarily balance.

(2) [70] contracted or attributed amounts from storage.

SOURCES: TCPL Facilities Planning and Union Gas answer to Gaz Metropolitain interrogatory #1, EBRO 405-2, November 8, 1985.

TABLE 6-3

EXPORT FACILITIES

TransCanada PipeLines Limited
Western Section, Central Station, Great Lakes

Capabilities Versus Requirements
In Operating Year 1986-87

	Winter Peak Day ($10^6 m^3/d$)	Summer Peak Day ($10^6 m^3/d$)	Winter Season ($10^9 m^3$)	Summer Season ($10^9 m^3$)	Annual ($10^9 m^3$)
Western Section					
1. System Deliveries	119.50	95.93	17.59	21.69	39.28
2. TCPL Fuel Downstream of Stn. 41	3.53	3.06	0.47	0.58	1.05
3. Western Section Requirement (1+2)	123.03	98.99	18.06	22.27	40.33
4. Western Section Capability	129.09	117.07	18.29	23.31	41.60
5. Western Section Excess (4-3)	6.06	18.08	0.23	1.04	1.27
Great Lakes					
6. System Capability	41.48	38.76	5.95	7.69	13.64
7. Existing Exports	14.81	14.81	2.11	2.53	4.64
8. New Exports	4.04	4.04	0.69	0.79	1.48
9. Transco STS Injections	-	2.13	-	0.28	0.28
10. Transp. Capability for TCPL (6-7-8-9)	22.63	17.78	3.15	4.09	7.24
Central Section/Great Lakes					
11. East of Stn. 41 Requirement	71.89	53.49	11.06	14.58	25.64
12. GLGT Transp. Capability for TCPL (10)	22.63	17.78	3.15	4.09	7.24
13. Central Section Capability	55.97	51.14	7.94	10.52	18.46
14. Excess at Lisgar/Dawn (12+13-11)	6.71	15.43	0.03	0.03	0.06
Total System					
15. Excess at Lisgar/Dawn (Lesser of 5. and 14.)	6.06	15.43	0.03	0.03	0.06

SOURCE: TCPL Export Facilities Application May 1984.

It is assumed that the projected annual volume throughput would not change. With the above peak day requirement, the TCPL system annual load factor would change from a projected 97.7% on the existing system to 52.0% on the peaking system (Table 6-4).

In order to assess the impact of this change on the TCPL rate base and the rates charged for transportation service, it is assumed that the revised system was developed in the same time frame as the existing system. This allows the historic costs in the current rate base to be used to estimate the rate base of the revised peaking system. Table 6-5 presents a derivation of the rate base and unit costs for the system which have been developed from the Sept. 30, 1984 cost of service determinations. The unit rates developed assume that a direct relationship exists between the rate base and system peak throughput capability. Indications from TCPL are that this assumption can be used as an approximation. The revised rate base would be approximately 72% greater than the September 30, 1984 figure.

The increase in pipeline facilities and operations is also assumed to cause a proportionate increase in fixed operations and maintenance expenses, along with the rate base related expense items. Thus the cost of service, net of the cost of gas sold and variable costs, can be expected to increase in direct proportion to the system peak throughput capability. Variable transmission costs are assumed to remain the same although reduced efficiency of operation at lower load factors would tend to increase unit variable costs. The resulting unit costs of transmission by TCPL are:

to Dawn station	$\$54.98/10^3m^3$
to Sheridan (Lisgar)	$\$63.23/10^3m^3$

TABLE 6-4

TransCanada PipeLines Limited
System Load Factor

Existing System			
1986-87	winter peak day	71.89	10^6m^3
	annual volume	25640	10^6m^3
	average day	70.25	10^6m^3
	load factor $\frac{70.25}{71.89}$	= 97.7%	
Revised System			
	peak day	135.205	10^6m^3
	average day	70.25	
	load factor $\frac{70.25}{135.205}$	= 52.0%	

TABLE 6-5

TransCanada PipeLines Limited
Derivation of Increased Rate Base and Cost of Service

Existing Rate Base (Sept. 30, 1984)		$ 2,581,360,000
Peak throughput capability (Central Section/Great Lakes)		78,600 $10^3m^3/d$
Unit investment cost		$32,842/10^3m^3/d$
Revised peak throughput capability		135,205 $10^3m^3/d$
Revised system rate base		$ 4,440,400,000
Net Cost of Service (Sept. 30, 1984) - transportation only - excludes cost of gas		$ 1,128,765,000
Volume/distance units		80,141,191 10^6m^3 km
Unit Cost		$ $1.4085/10^3m^3$ - 100 km
to Dawn Station (2613 km)		$ $36.804/10^3m^3$
to Sheridan station (3005 km)		$ $42.325/10^3m^3$
Cost of Service		
Fixed portion		$ 773,822,000
Variable portion		354,942,000
Total		$ 1,128,764,000
Revised fixed portion		
773,822,000 x 135205/78600	=	$ 1,330,974,000
Add original variable		354,942,000
		$ 1,685,916,000

Unit costs:

	$2.104/10^3m^3$ - 100 km
to Dawn	$54.98/10^3m^3$
to Sheridan	$63.23/10^3m^3$

Increase in transportation cost of service is:

$ 1,685,916,000	
-1,128,764,000	
$ 557,152,000	

These increased costs will flow directly to Union and Consumers' cost of service determinations. The additional transportation costs to TCPL which can be attributed to the increase in peak throughput capability is $557.152 million.

.1 Existing Storage and Transmission Costs

From Union's most recent filing for gas storage rates, the 1986-87 projected gas storage costs is made up of the following:

	$000
Operating and maintenance expense	10,698
Investment carrying costs	45,425
Transfers (to transmission)	(8,651)
Total allocated costs for storage	47,472

These costs would no longer be incurred by Union since the TCPL system is assumed to provide peaking service. In addition it is assumed that Dawn to Trafalgar compression and transmission service would no longer be provided by Union and the corresponding costs could also be removed from Union's cost of service. These costs are summarized below:

	$000
Operating and maintenance expense	12,145
Investment carrying costs	53,370
Transfers (from stroage)	8,651
Total cost of transmission	74,166

Thus the total cost related to the storage and transmission functions which would no longer be borne by Union is $121.638 million.

The corresponding costs allocated by Consumers' to their storage and storage-related transportation functions is:

	$000
Tecumseh storage	13,900
Union storage	4,900
Union transportation	31,000
Total	49,800

Thus the total storage and transmission costs which would be displaced under the TCPL peaking system scenario would be $171.438 million, resulting in a net additional cost to Central and Eastern delivery zone customers of $385.714 million.

.2 Effect on Retail Rates

There are two basic approaches which can be taken in the allocation of additional transportation costs to the various customer groups. The first assumes that only the existing volumes provided from storage are responsible for the costs incurred in providing the storage service. Also the seasonal volumes demanded by each storage customer can be represented by the peak day delivery contracted or allowed for in forecasts. This method does not take into consideration the fact that the gas markets would have developed differently in the absence of economical storage and that in effect all users of the pipeline system currently benefit from seasonal storage.

The second approach takes the above factors into account by assuming the present gas market has developed in the absence of underground storage facilities. Thus all customers are responsible for pipeline system investment which can be allocated in proportion to each customer group's peak day demand on the system.

The first approach can be developed using the general methods currently employed for allocating existing storage and storage-related transmission expenses to the various firm customer categories. This procedure assumes that the present market proportions of firm and interruptible gas do not change due to the impact of a significantly larger rate differential between these two types of service.

The analysis is carried through to the development of additional costs to each customer group, although it is recognized that the second approach, introduced above, is more appropriate. The analysis of the differences in the resulting allocations under the two methods provides information which is useful in establishing the benefits of storage for the various system elements.

A breakdown of the peak day sales levels for the distributing utilities and other customers which is currently being provided by Union and Tecumseh from storage is given in Table 6-6. Allocation factors are also calculated based on the assumption that peak day requirements of each storage customer represent cost responsibility on the present storage facilities. These allocation factors can then be used to represent customer peak responsibility for the additional TCPL transportation costs. It is recognized that allocating these additional costs on the basis of peak day volume responsibility does not match the current cost allocation procedure. However, the method used does give an indication of the relative magnitudes of increased costs applicable to the various customer categories.

TABLE 6-6

Peak Day Volumes from Storage 1986/87

	$10^3m^3/d$	Allocation Factor
Consumers'		
Tecumseh	30 110	0.4628
Union	5 850	0.0899
Kingston P.U.C.	70	0.0011
Gaz Metropolitain	1 900	0.0292
I.C.G. (Ontario)	1 000	0.0154
Union	26 130	0.4016
Total from storage	65 060	1.0000

The next step is to apply the allocation factors to the TCPL additional costs to arrive at the costs which will be borne by each current storage customer. Table 6-7 gives a tabulation of this cost allocation.

TABLE 6-7

Allocation of Revised System Peak Day Costs

	Allocation Factor	Allocated Amount
		($000)
Consumers'	0.5527	213 184
Kingston	0.0011	424
I.C.G. (Ontario)	0.0154	5 940
Gaz Metropolitain	0.0292	11 263
Union	0.4016	154 903
	1.0000	385 714

If it is assumed that all TransCanada Central and Eastern delivery zone markets should be allocated a portion of the additional costs, according to their peak day demands on the system, the assignment of costs shown in Table 6-8 will result.

TABLE 6-8

Allocation of Peak Day Costs -
All Central and Eastern Deliveries

	Peak Day Volume			Allocation Factor	Allocated Amount
	Storage	TCPL	Total		
	10^3m^3				($000)
Consumers'	35 960	20 955)	59 955	0.4434	171 026
ACQ		3 040)			
ICG (Ontario)	1 000	10 530	11 530	0.0853	32 901
Quebec	1 900	16 714	18 614	0.1377	53 113
Kingston	70	364	434	0.0032	1 234
Niagara Gas	-	1 135	1 135	0.0084	3 240
Vermont	-	788	788	0.0058	2 237
Tennessee Gas	-	4 958	4 958	0.0367	14 156
Union	26 130	7 650)	37 791	0.2795	107 807
ACQ		4 011)			
			135 205	1.0000	385 714

Using the latter method of allocating additional TransCanada system costs is perhaps more realistic, given the initial assumption that the transportation system without storage has developed over the years to serve the present market demand profiles. Therefore, in the following analysis of the impact on elements of the gas system, the approach taken is to spread the additional costs over all customers imposing peak day demands on the revised TransCanada system.

Union Gas

From the latest cost allocation study filed by Union the following peak day responsibility factors are derived for storage deliverability and transmission functions.

Residential	35.4%
Commercial and Industrial (non-contract)	40.8
Special Large Volume	9.9
Wholesale	3.9
Non-Firm	10.0
	100.0

Assuming the proportionate peak responsibilities do not change, the distribution to Union's customers of additional transportation peaking costs would be:

	$000	Annual Volume ($10^6 m^3$)	$/$10^3 m^3$
Residential	38,164	1,498	25.48
Commercial and Industrial	43,985	2,333	18.85
Special Large Volume	10,673	1,416	7.54
Wholesale	4,204	235	17.89
Non-firm	10 781	1,764	6.11
Total	107,807	7,246	14.88 Average

For the Residential and non-contract commercial and industrial customers (Rate M2) the above changes compare to an existing rate of \$207.442 per $10^3 m^3$ for the first 1400 m^3 per month consumption. This would represent approximately a 12% increase for small residential consumers, with somewhat lower increases for commercial and small industrial customers on the M2 rate. If the cost of gas (commodity) component is removed from the average unit rate, the \$25.48/$10^3 m^3$ represents a 44% increase over the balance of the cost of service.

The higher load factor customers would not have as great an increase since they depend proportionately less on seasonal storage. Average increases would be in the range of 5%, based on the current average rate range of \$148.153 to \$161.641 per 10^3m^3.

Similar calculations for retail customers of Consumers' result in increases of the same magnitude for the various classes of retail customers. For ICG customers there is a slightly lower impact on retail rates due to the lower level of dependence on underground storage and the fact that costs for peaking services from TransCanada are already included in the retail rates.

Customers east of Ontario would see smaller increases due to their lower proportionate use of seasonal storage and thus greater use of firm CD service from TCPL.

.3 Effect on TransCanada PipeLines

The impact on elements upstream of the Ontario delivery area is not as easily quantified as that on the existing storage customers. For TransCanada it is obvious that with the large increase in the rate base the earnings on rate base would be significantly higher. As the revenue requirement (and thus the earnings) are set on a cost of service basis by the National Energy Board, there would be no windfall to the utility. The increased earnings would be required in order to support the higher levels of external financing required for the pipeline operations.

Changes in cash flow patterns through the year would be expected due to the significantly reduced load factor. Current operations provide a relatively constant distribution of revenue over the calendar year, as shown in Table 6-9. An indication of the quarterly revenue distribution under the revised system operation can be obtained from an examination of the monthly sales of the distribution

utilities. The estimated quarterly breakdown of revenues is given for comparison in Table 6-9.

The indicated shift from the almost constant revenue stream to a definite seasonal variation will be mitigated to a major extent by the fact that TransCanada will be purchasing gas from the producers on a similar seasonal schedule. However, a significant portion of the pipeline operator's costs are fixed costs and would require increased allowances for working capital, due to the variability of revenues.

TABLE 6-9

TransCanada Revenue by Quarter
%

Quarter	1985 Revenue(1)	Estimated Revenue Under Revised System(2)
1	27.1	45
2	24.2	15
3	22.1	10
4	26.6	30

NOTES: (1) From TCPL 1985 Annual Report.
(2) Estimate based on distribution utility reported monthly sales.

.4 Effect on NOVA and Alberta Producers

Without the use of Ontario underground storage the effect of seasonal volumes required by the pipeline would fall mainly on the system producers and, to the extent that gas production is gathered and stored in Alberta, on NOVA. If the gas processing plant capacity were to be kept as low as possible, the clean or sweet gas would have to be stored, ready for delivery to the TCPL pipeline. Thus along with the increased pipeline transportation costs there would be cost pressures on the producers due to the large fluctuations in volume requirements through the year.

If storage facilities were not developed in the West the producers would require additional wells either in existing or new producing areas in order to meet deliverability requirements. The effect would be to reduce the effective netbacks or margins to the producers assuming the same formula of fixing the Eastern Gate price is continued. No attempt has been made to quantify these effects due to the complex nature of the pricing arrangements.

.5 Effects on Other Elements

The effect of higher pipeline charges on gas volumes flowing through Ontario to Quebec and export markets is given below in Table 6-10. The level of additional charges is similar to that calculated for wholesale customers of Union Gas.

Table 6-10

Additional Pipeline Charges
for Export Gas Volumes

Customer	Allocated Amount ($'000)	Projected Annual Volumes(1) ($10^6 m^3$)	$/$10^3 m^3$
Niagara Gas	3,240	241	13.44
Vermont	2,237	156	14.34
Tennessee	14,156	1,810	7.82
Gaz Metro	53,113	3,904	13.60

(1) From TCPL export facilities filing.

It is likely in the case of export volumes that these increases in charges would have an impact on the volumes contracted for. The availability of supplies from other pipelines in the northern United States would also affect the export market situation.

Under the expanded TCPL system assumed the existing storage companies and landowners would no longer be a part of the gas supply system and would thus forego current revenues.

6.5 SUMMARY

The analysis of existing utility rates and storage rates provides a basis for developing allocations to the various customer groups of the estimated increased transportation costs which would be incurred in the absence of Ontario underground storage. When these allocations are compared with existing rates the indicated increases are greatest for the smaller utility customers. These customers generally are seasonal or space heating customers and thus are heavily dependent on seasonal underground storage. The impact on the larger customers, although not as large in percentage terms, is certainly significant in dollar terms when the large annual volumes are considered. These are also the customers which are able in most cases to switch easily to competing fuels.

It is evident that the cost implications on gas markets of not having the large economic storage pool capability in southwestern Ontario would have resulted in the gas supply and delivery system developing in a considerably different way. The additional costs developed in this analysis give a preliminary indication of the benefits which the geography of Ontario and the systematic development of this resource are providing.

PART 7

ONTARIO STORAGE EMERGENCY CAPABILITY

7.1 INTRODUCTION

Part 5 covers in detail the natural gas delivery system supplying Ontario. The combination of the northern pipeline system of TransCanada and the southern pipeline system of Great Lakes provides an excellent and normally secure source of gas for the Province of Ontario. The existence of large storage fields near the main area of consumption also makes a contribution to the security of supply. In this part the capability of the Ontario gas storage system to respond to disruptions in western pipeline supply is discussed.

7.2 PRINCESS, ALBERTA INCIDENT

An explosion and fire occurred at the Princess, Alberta compressor station of NOVA, in February 1981. The location of the station piping put isolation and bypass valves too close to the main station to withstand the intense heat created by the fire. As a result the valves were badly damaged and could not be operated. The entire NOVA system was shut down and only minor supplies from smaller fields near the Saskatchewan border were available to eastern Canadian and export markets.

The interruption occurred at a time of extremely cold weather in eastern Canada and therefore during a high gas demand period.

Immediately on obtaining the news from NOVA, and its own pipeline control station at Burstall, Alberta, TransCanada notified the dispatch offices of the gas distributors in all areas downstream of Alberta. A control centre was established by TransCanada at its Toronto dispatch centre. Ontario distributors set up similar control centres at their dispatch offices.

All interruptible customers were told to immediately cease their gas use. The firm industrial customers were put on notice as to possible curtailment or interruption. The Ontario Ministry of Energy prepared plans to order curtailment of customers in accordance with a priority system approved for just such an emergency.

All exports to the United States were discontinued and urgent requests were made for emergency supplies from U.S. pipeline companies to be delivered to Canada by reversing the normal pipeline flow. All export customers made some gas available at all of the export points.

Union and Tecumseh storage reserves were made available to the overall eastern Canadian gas market.

The line-pack in TransCanada and Great Lakes combined with Ontario storage and emergency supplies from the U.S. were sufficient to meet the curtailed Canadian market. However, by the time western Canadian gas began to flow after the 96 hour interruption, alternate supplies were beginning to run low.

The serious supply emergency caused by the Princess fire resulted in the redesign and reconstruction of the bypass and isolation valving around all NOVA and TransCanada compressor stations.

7.3 REVIEW OF ONTARIO UNDERGROUND STORAGE

The current working storage capacity in southwestern Ontario underground facilities is summarized below:

	$10^6 m^3$
Union	2661.3
Tecumseh	1472.0
Consumers'	12.5
Total	4145.8

The 1987-88 peak day deliver from the storage fields is expected to be:

	10^3m^3
Union	34,950
Tecumseh	30,110
Consumers'	185
Total	65,245

7.4 EMERGENCY SITUATION

The worst single situation which might be contemplated would be the loss of the northern section of the TransCanada pipeline. Normally it would be expected that the worst that could happen would be the loss of a single loop of the dual pipeline system but it is conceivable that a compressor station and both lines could be put out of commission simultaneously thus disrupting gas flow completely. It is further assumed that this incident would take place during the peak demand period of the year. Discussions with pipeline experts indicate that if the location were in a remote area of Northern Ontario emergency repairs to the pipeline would take about five days. This would require that portable compression facilities be used to restore service to normal throughput levels on a temporary basis.

Figure 6-1 indicates a 1987-88 peak day flow rate of the northern system of TransCanada to Central and Eastern Zones is 57,491 10^3m^3.

It is further assumed that all natural gas utilities supplying various classes of service would maintain a priority of service schedule. Hospitals and similar institutions and residential would receive top priority on such schedules. Since most hospitals

are included in the commercial rate category, it is assumed that 20 percent of the commercial peak day will require service along with the total residential peak requirements. The remaining assumptions are:

- The pipeline damage occurs on the northern section of TransCanada pipeline near the Manitoba border.

- Underground storage is at or near full working capacity as it would be entering the peak period.

- All markets east, north and south of the Trafalgar station would be supplied including Consumers', I.C.G. Utilities, Kingston, Niagara Gas, Quebec and Vermont.

- All gas supplies would be delivered through the Dawn-Trafalgar pipeline.

- I.C.G. Utilities' Hagar LNG plant would supply the North Bay to Espanola area.

Based on the above assumptions and making use of the information in Part 5, Section 5.5.2, the peak day requirements of the markets described above are estimated to be:

ESTIMATED PEAK DAY REQUIREMENTS
(emergency conditions)

	$10^6 m^3$
Consumers'*	20.5
I.C.G. Utilities	8.5
Kingston	0.2
Quebec	6.5
Vermont	0.4
Total	36.1

*NOTE: Consumers' includes Niagara Gas.

7.5 SUMMARY

Under the conditions outlined, the storage gas flowing at the full capacity of the Dawn-Trafalgar pipeline would probably meet the essential requirements of the Ontario market excluding the Union Gas area, and that of Quebec and Niagara Gas and Vermont exports.

Union's storage and supplies delivered by Great Lakes would supply all of southwestern Ontario's demands, with probably no curtailment except normal industrial interruptions.

The gas in storage entering the peak period would probably look after Consumers' and other Eastern requirements for almost 60 peak days.

Union's storage would look after Union's full firm requirements for up to 70 peak days.

The capacity of the Dawn-Trafalgar pipeline currently is the constraint in moving storage gas to markets further east, in the event of disruption in the northern pipeline flow.

I.C.G. Utilities' LNG plant at Hagar would probably meet the residential and essential commercial requirements of the North Bay to Espanola area.

PART 8

PROPOSED LNG FACILITY

8.1 INTRODUCTION

In March, 1985 Consumers' Gas announced that investigations were underway of potential sites for a $100 million liquefied natural gas (LNG) storage project planned for operation in the winter of 1988/89. The site selection process took place over a period of several months and resulted in the purchase of approximately 180 hectares of land in the Cobourg-Brighton area, east of Toronto.

During the site selection process Consumers' conducted several public meetings in the general site area to discuss the proposed plant with local residents and farmers. Many concerns were expressed regarding safety to the public and the environment and the local residents formed a group which called itself "The Concerned Citizens Against LNG." This group has prepared and distributed a considerable amount of material regarding the safety issues in the storage and handling of heavy gases such as Liquefied Petroleum Gases (LPG) and LNG. The group is an active intervenor at the Ontario Energy Board Hearing currently in progress in Cobourg, Ontario.

8.1.1 LIQUEFIED NATURAL GAS (LNG)

LNG is natural gas that has been converted from a vapour into a liquid. The process required to do this is much the same as converting steam or water vapour into water, i.e. reducing the temperature. With natural gas the temperature required to make it into a liquid is very low, -160 degrees celsius. The liquefaction of natural gas is accompanied by a substantial reduction in volume. This makes it possible to store over 600 times more natural gas in liquid form in a low pressure storage tank without altering the quality of the gas.

There are three basic steps involved in the LNG storage process:

Liquefaction
Storage
Vaporization

During liquefaction, natural gas is processed to remove all traces of impurities and reduced in temperature to -160 degrees celsius. It is then pumped into the storage tank for storage.

In the storage stage, the low temperature is maintained by insulation and continuous vaporization of a small amount of the LNG. This is known as "boil off." In this way the LNG can remain in storage without any further refrigeration. The boil off gas is returned to the pipeline system.

When gas is needed during peak periods of winter demand, the LNG is pumped from storage into vaporizing units where it is converted back into natural gas. The natural gas is returned to the pipeline system as needed to meet peak demands.

8.1.2 CONSUMERS' PLANT SPECIFICATIONS AND DESCRIPTION

Consumers' Gas has provided the following information regarding their proposed LNG Plant at Cobourg.

Estimated cost	$100 million
Storage capacity	56 $10^6 m^3$
Vaporization rate	8.5 $10^6 m^3/d$
Liquefaction rate	0.28 $10^6 m^3/d$
Number of days to fill	200
Outer tank dimensions	Height - 50 m, diameter - 60 m
Number of employees	15

The storage tank is the largest and most visible component of the proposed LNG plant. At 50 m high it will stand as tall as a 14 story building. The construction of the tank consists of two shells. The outer one is constructed of ordinary carbon steel and the inner one constructed of a special 9% nickel steel providing very high strength at the extremely low temperatures to be employed. The space between the two tanks is filled with a very efficient insulation. An artist's drawing of the proposed plant is included as Figure 8-1.

8.1.3 PURPOSE OF THE PLANT

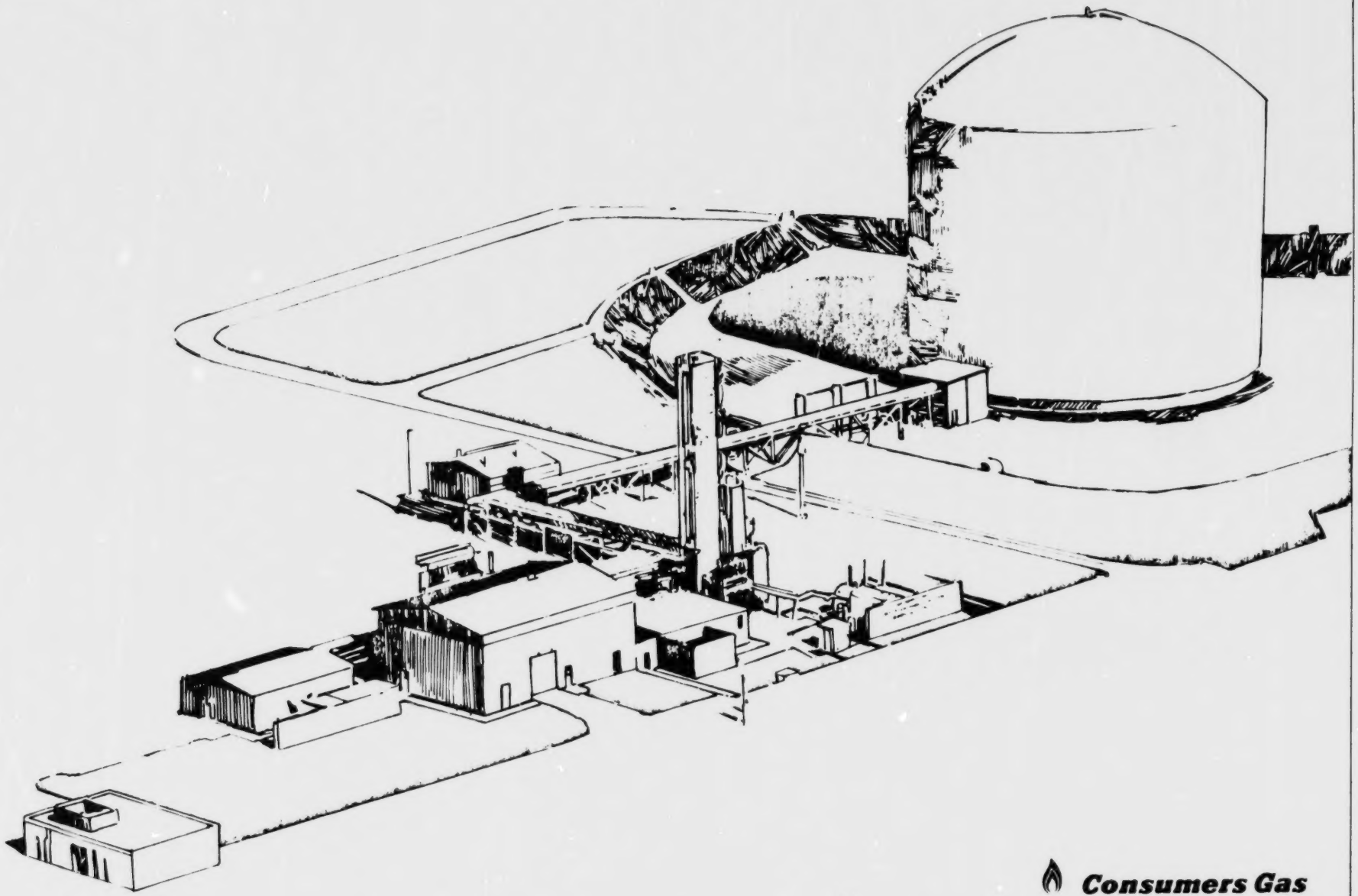
Consumers' state that the purpose of the LNG plant is to shave the needle peaks that have developed due to the low load factor residential market growth. The effect of conservation and the acceptance of the high efficiency furnaces has resulted in reduced use per customer but with as high or higher peak day consumption per customer. The result of this trend is a sharp peak that usually occurs on a winter weekday that combines low temperature with strong winds. The large number of conversions to natural gas which has occurred over the past several years, due in part to favorable pricing and the national off-oil program has caused a substantial increase in residential space heating sales.

The overall result of this situation is claimed to be a degeneration of Consumers' annual load factor. A report written by Stone & Webster which was filed by Consumers' in response to an O.E.B. "Staff Interrogatory" in the current LNG Hearing indicates that the system load factor is projected to decline from 43% in 1982 to 39% in 1992.

Figure 8-1

Typical LNG Storage Plant

Artist's Rendering



Consumers Gas

8.1.4 IMPACT ON CURRENT GAS SUPPLY AND DELIVERY

The LNG peak shaving plant proposed by Consumers' has the capability of supplying 8.5 million cubic metres per day for a period of 6.5 days. From information supplied at the LNG hearing, the needle peak is very sharp and has a short duration. The plant capability appears to meet this requirement. However the amount of natural gas stored by the proposed LNG plant compared to that stored in the underground storage fields is very small.

With the current underground storage working capacity of 4,882 10^6m^3, the proposed LNG plant capacity of 10^6m^3 represents about 1 percent of the current underground storage.

In addition to providing a probable solution to Consumers' current and short term peaking problems, the proposed plant would provide 8.5 10^6m^3 per day to supplement TransCanada's supply in the east central part of the province. However this volume is only about 23% of the 37 10^6m^3 per day carried by TransCanada in that section of the pipeline system. In the absence of detailed information on the peak day demands of various areas of the province it could be assumed that the 8.5 10^6m^3 per day available from the Consumers' plant could supply the residential and critical demands of the general area.

8.1.5 COMPARISON WITH UNDERGROUND STORAGE

To put the peak shaving systems in perspective it is useful to compare some of the characteristics of each type of storage.

LNG can deliver 8.5 million cubic metres of natural gas with a capacity of only 56 million cubic metres. The full storage capacity can be depleted in 6.5 days and takes 200 days to refill. The ratio of deliverability to reserves is 1 to 15.

UNDERGROUND STORAGE can deliver 65.2 million cubic metres per day with working capacity of 4882 million cubic metres. The full storage capacity is depleted over a period of four or five months and takes about the same time to refill. The ratio of deliverability to working capacity is 1 to 75.

Figure 8-2 illustrates the Consumers' daily load duration curve for 1984 and the impact of the needle peak. By operating the LNG over the peak ten days, with a maximum sendout of 8.5 $10^6 m^3$ on the peak day, this needle peak can be significantly reduced. Figure 8-3 is a graphical representation of the forecast monthly operation of Union's underground storage (for fiscal 1986). This shows the filling period of seven months and withdrawal period of five months.

8.2 I.C.G. UTILITIES (ONTARIO) LTD., LNG PLANT

I.C.G. Utilities operates a LNG plant in northern Ontario at Hagar in the Sudbury area. The plant was constructed in 1968 and commenced operation in January 1969. The plant has been in operation since that time.

8.2.1 SPECIFICATIONS

Storage capacity	28 million cubic metres
Vaporization rate	2.5 million cubic metres/day
Liquefaction rate	0.14 million cubic metres/day
Number of days to fill	200
Outer tank dimensions	Height, 27 m, diameter - 36 m

FIGURE 8-2

FORECAST LOAD DURATION

SENDOUT FISCAL 1984 BASECASE
SENDOUT FISCAL 1994 BASECASE
SENDOUT FISCAL 1994 OPTIMISTIC CASE NORMAL
SENDOUT FISCAL 1994 ENERGY TAX REDUCTION CASE NORMAL

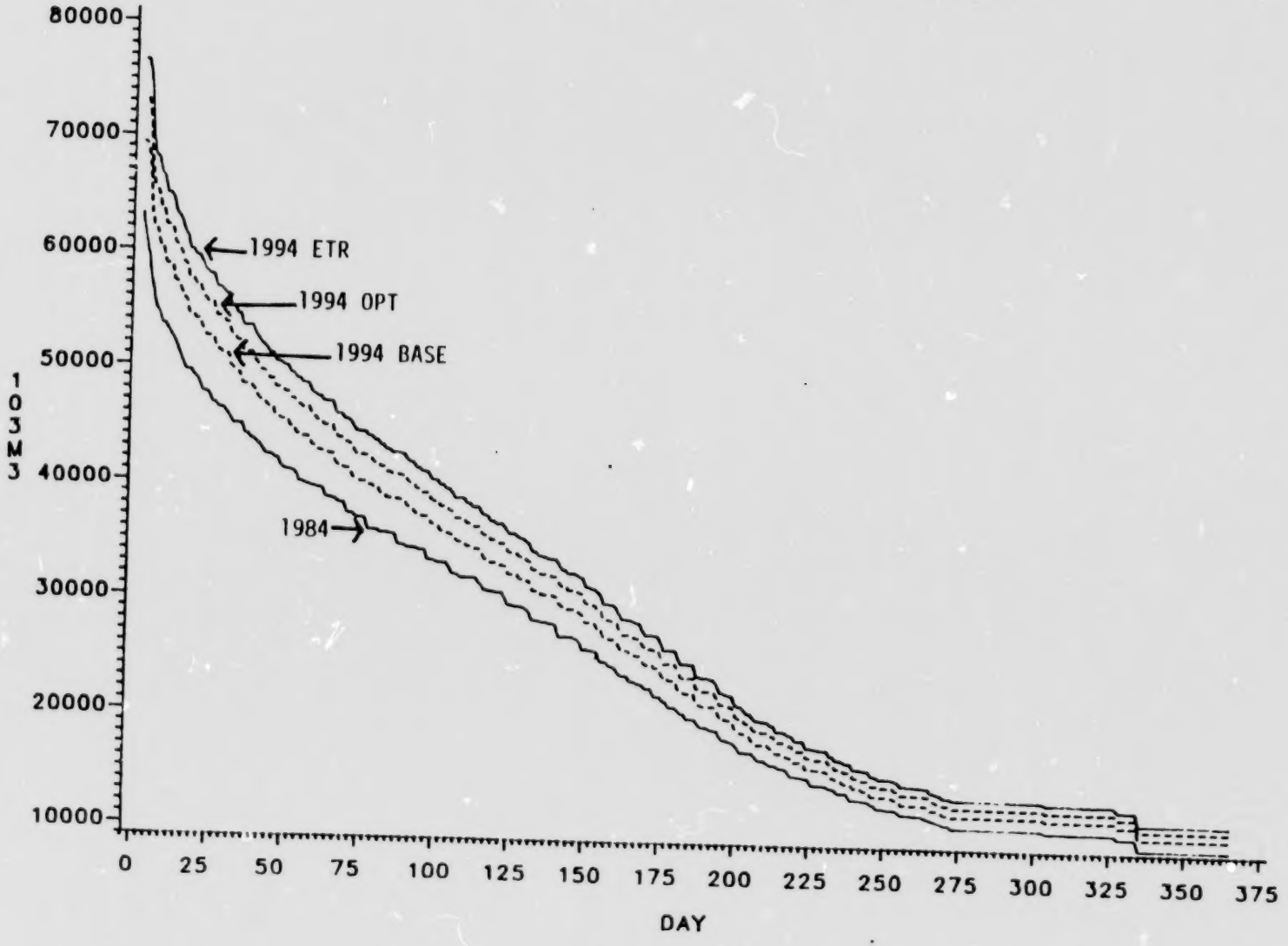
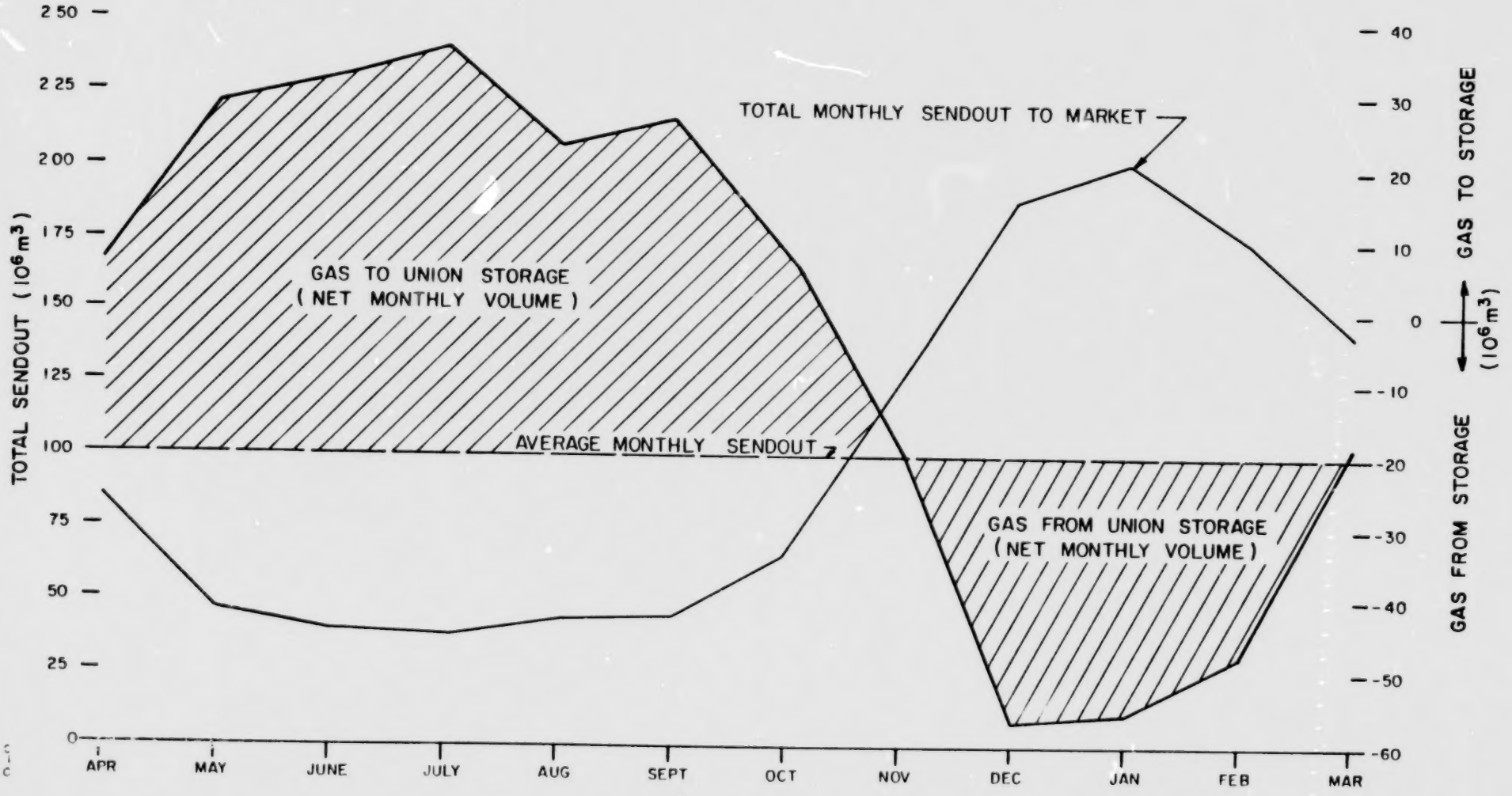


FIGURE 8-3

UNION GAS LIMITED

MARKET REQUIREMENTS AND STORAGE OPERATION
FISCAL 1986



The plant is operated as a peak shaving and load balancing plant and is located on the North Bay to Espanola transmission line owned by I.C.G. Utilities.

8.3 SUMMARY

Based on the information available, the LNG plant proposed by Consumers' Gas appears to meet the specific requirements of shaving the needle peak caused by the increased and changing residential market.

The characteristics of LNG peak shaving are very different from those of underground gas storage and each appears to fill a different need. The role of underground storage is more to level a long duration seasonal peak than to shave the short duration needle peak.

The combination of the two types of storage appears to provide a complementary solution to the temperature sensitive nature of the Ontario market.

Although small in comparison to the overall peak day of the markets supplied by the TransCanada line (on which the LNG plant is to be located), the 8.5 million cubic metres per day output could provide an emergency source of supply to residential and essential commercial customers in the area of east central Ontario.

PART 9

SUMMARY AND CONCLUSIONS

9.1 SUMMARY

In the development of the natural gas supply and delivery system the existence of a large and economical storage capability near the central Canada energy markets was a key element. The availability of this gas storage was known well before the initial planning of the TransCanada system and certainly formed an essential part of the feasibility of the pipeline.

Without the existence of Ontario seasonal storage facilties the low load factor space heating market could not have been developed and the large volume industrial and export markets would have been the only viable loads. These are also the most sensitive loads to pricing of alternative energy forms and thus would have presented a greater risk situation for the pipeline. The relatively more stable residential and small commercial markets, when coupled with seasonal load levelling through storage, provided an attractive balance for the pipeline system.

The Ontario transmission, storage and distribution system has evolved into an efficient network which serves all major population centres in the province. The Ontario market accounts for approximately 75% of all TransCanada domestic annual sales volume. Having the large gas storage capability at a distance of three thousand kilometres from the gas supply and in close proximity to the major load centres has provided the balance and security necessary to develop this significant load.

9.2 CONCLUSIONS

The sections below outline the specific points or conclusions which may be drawn from each subject area of the study and generally follow the order of presentation in this report. In some cases the conclusions reached are based on preliminary and limited analysis, due to the range of subjects considered in the study. It is therefore cautioned that firm conclusions should not be drawn until more detailed analysis of these individual items can be made.

9.2.1 UNDERGROUND STORAGE OPERATIONS

Based on an examination of current underground storage operations and knowledge of other possible types of storage, it is evident that the pinnacle reef formations are the most suitable means of providing seasonal gas storage in Ontario. Storage in stratigraphic geologic traps does not provide the high deliverability to working capacity ratio which is desirable for economy of seasonal storage operations. The lack of reservoir closure is a further potential problem in this type of reservoir.

The present integrated operation of storage and transmission facilities in southwestern Ontario provide an efficient means of re-timing market demands, to the benefit of all elements of the natural gas industry.

9.2.2 GEOLOGY

The incidence of pinnacle reef formations in southwestern Ontario is unique to this part of Canada although they are also found in neighbouring states. There is a limited occurrence of this type of geologic trap because of the limited number of sedimentary formations.

The remaining unexplored areas of Lakes Erie and Huron could hold promise for gas reservoir discovery since the various reef belts run in close proximity to them.

9.2.3 POTENTIAL STORAGE

From a review of other underground formations it is concluded that none provide the operational characteristics and economy necessary to allow their development at this time. The next best comparable storage formation (to pinnacle reefs) appears to be aquifers, but their development is not warranted now.

There is however a large potential for additional storage in southwestern Ontario in existing pinacle reef formations using delta pressuring techniques and additional depleted reservoirs. Extensive storage operations in Michigan could provide an alternative to Ontario storage, since the Great Lakes pipeline is routed through this region.

9.2.4 GAS SUPPLY AND DELIVERY

The present gas supply and delivery system in Canada provides service to practically all populated areas of Ontario, while maintaining virtually full utilization of the 3,000 kilometre TransCanada pipeline throughout the year.

Underground seasonal storage has proven to be an important and reliable component of this delivery system. The ICG Utilities LNG storage facility has provided safe and efficient peak supply service in the Sudbury area for over eighteen years.

9.2.5 BENEFITS OF STORAGE

Without the timely development of Ontario storage (and assuming similar customer mix and load profiles) it is evident that a vastly different gas supply and transmission system would have been required. However the additional costs incurred in building the TransCanada system with capability to meet peak day demand would have precluded the development of much of the market now being served.

If it can be assumed that the additional costs of the required peaking system would be allocated to the various customer classes in proportion to their peak demands on the system, it is evident that significantly higher rates would be required. This would likely cause an eventual shift to more competitively priced energy forms.

It is apparent that current energy markets have seen a significant shift in the price advantage of gas over fuel oil. With this situation expected to continue at least over the short term, it is concluded that increases in retail gas rates to reflect the value of seasonal storage would not be supported in the market.

Since it is not possible to pass on the increased cost of service in the case without gas storage, it is concluded that the current economies provided by gas storage are necessary to maintain market share. Thus any sizeable increases utility costs of service (such as landowner compensation) would have an adverse impact upon present markets and future market growth.

9.2.6 EMERGENCY CAPABILITY OF STORAGE

From a brief overview of the emergency response capability of Ontario storage it is evident that storage has proven to be of value when supply disruptions have occurred. With current pipeline design the likelihood of a complete cutoff of supply is now remote but still possible. There are however, limitations to emergency capability due to the location of the storage remote from some of the load centres and pipeline transmission capability and the daily deliverability of the storage fields.

In order to properly quantify the benefits provided it would be necessary to analyse simulations of system operations under situations of supply interruption at various intervals during the peak season.

9.2.7 CONSUMERS' LNG PROPOSAL

It is considered that the proposed Consumers' LNG facility, while not appearing to have any impact on the overall Ontario supply situation, will provide the high deliverability necessary to reduce Consumers' needle peak while at the same time requiring limited storage capacity. The combination of the LNG plant and underground storage appears to provide a practical solution to the variability of market demands.

ONTARIO MINISTRY OF ENERGY

NATURAL GAS
STORAGE IN ONTARIO

APPENDICES

JULY 1986

Monenco Consultants Limited
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Rexdale, Ontario
M9W 5Z8

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APPENDIX I	TERMS OF REFERENCE
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APPENDIX VI	TRANSCANADA PIPELINES RATE DETERMINATIONS

APPENDIX I

TERMS OF REFERENCE

SCHEDULE A

Attached to and forming part of Agreement between Monenco Consultants Ltd. and Her Majesty the Queen dated March 5, 1986.

TERMS OF REFERENCE

Ministry Objective

- To provide a perspective of the role of Ontario storage in the overall gas supply system in Canada.
- To provide an inventory of the current storage facilities and their costs, and determine the potential for additional natural gas storage.
- To analyse the benefits of Ontario storage and to determine if these benefits are reflected in current rates and prices.
- To examine current utilization patterns of natural gas storage and determine their contribution to economic utility operations and energy security in Ontario.

Contractor's Task

1. Investigate and report on:

    1) History of storage in Ontario
    2) The role of storage in the overall gas supply system in Canada
    3) Current ownership, lease arrangements, and the regulation process of storage fields
    4) Investment of storage companies in field development, cushion gas, injection, collection systems, etc.
    5) Rates charges by storage companys for storage and transmission of gas from storage.

2. Provide a map of Ontario indicating:

    1) storage locations
    2) current storage volumes
    3) potential storage volumes, (new, non-active and suspended)
    4) supply and delivery transmission systems
    5) Ontario productions fields
    6) peak day gas flows

3. Investigate and report on potential storage indicating:

   1) geological data relevant to storage characteristics
   2) most suitable use(s)
   3) potential volume
   4) estimated cost to develop

4. Evaluate the current gas supply system in Canada and determine the costs or savings which would be incurred for each element of the system if Ontario storage did not exist. Use existing rate structures, gas volumes, customer mix, rates of return, etc. and estimate additional pipeline costs. Use currently approved rate-making, costing and depreciation methods to determine effect of costs or savings on rates.

   Elements of the gas supply system to be evaluated include:

   1) the landowner
   2) the storage company
   3) each of Ontario's distributors
   4) distributors and other customers east of Ontario
   5) TCPL
   6) export customers of TCPL
   7) natural gas producers in Alberta
   8) NOVA
   9) residential consumers in Ontario
   10) interruptible industrial consumers in Ontario
   11) firm industrial consumers in Ontario

5. Compare rates, etc. determined in 4 to those currently approved.

6. Review historical storage and usage data to determine the extent existing storage would meet an emergency supply interruption in the TCPL systems west of Ontario.

7. Identify the contribution that the proposed Consumers' Gas LNG facility makes to the Ontario supply and storage system and Consumers' Gas system.

APPENDIX II

GEOLOGY OF STORAGE

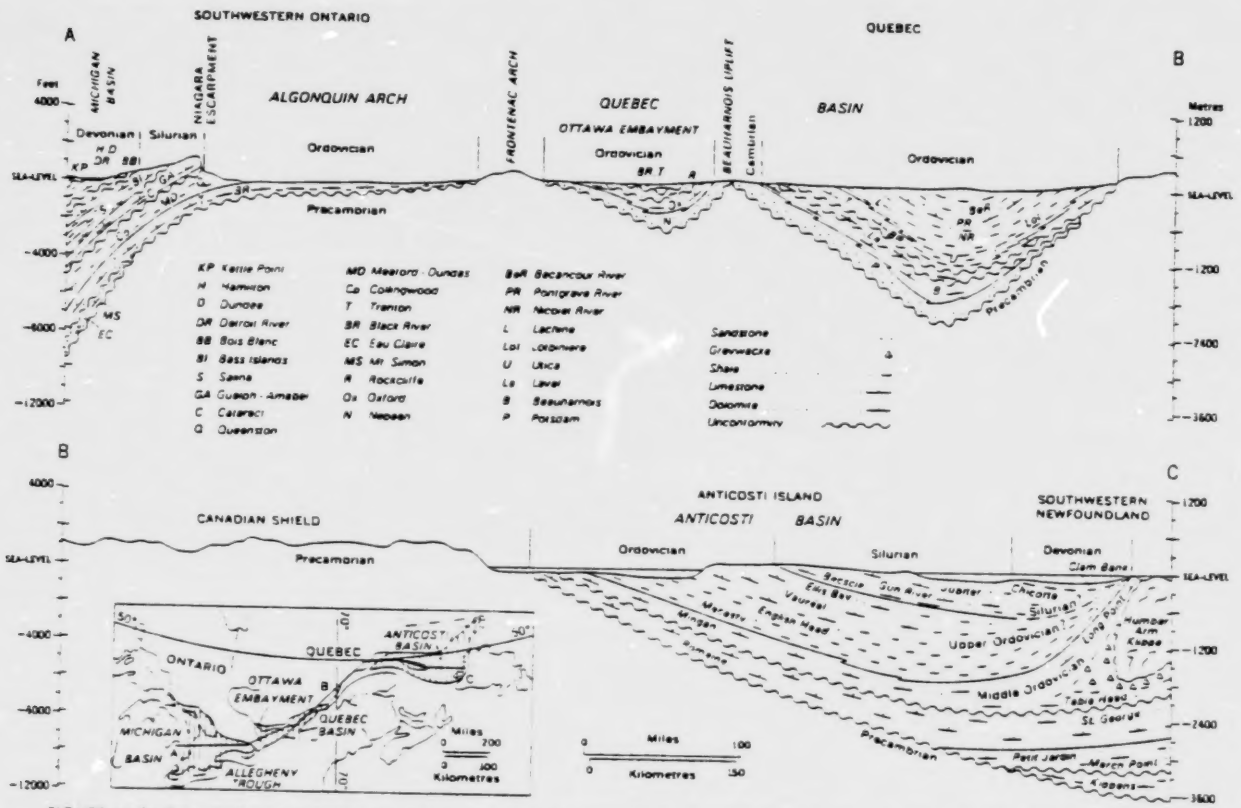


FIGURE VI-7. Cross-section of Paleozoic formations of the St. Lawrence Platform from Michigan Basin to Anticosti Basin (by B. V. Sanford).

From page 241, Sanford, 1976a,

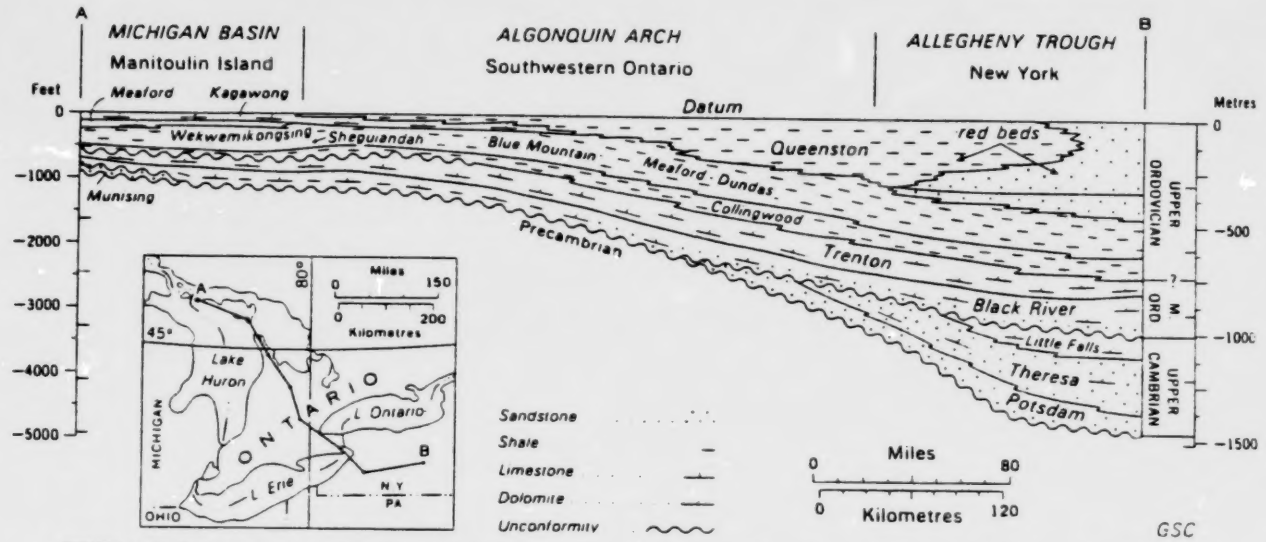


FIGURE VI-8. Cross-section of Cambrian and Ordovician formations in southwestern Ontario and northern New York (by B. V. Sanford).

From page 242, Sanford 1976a.

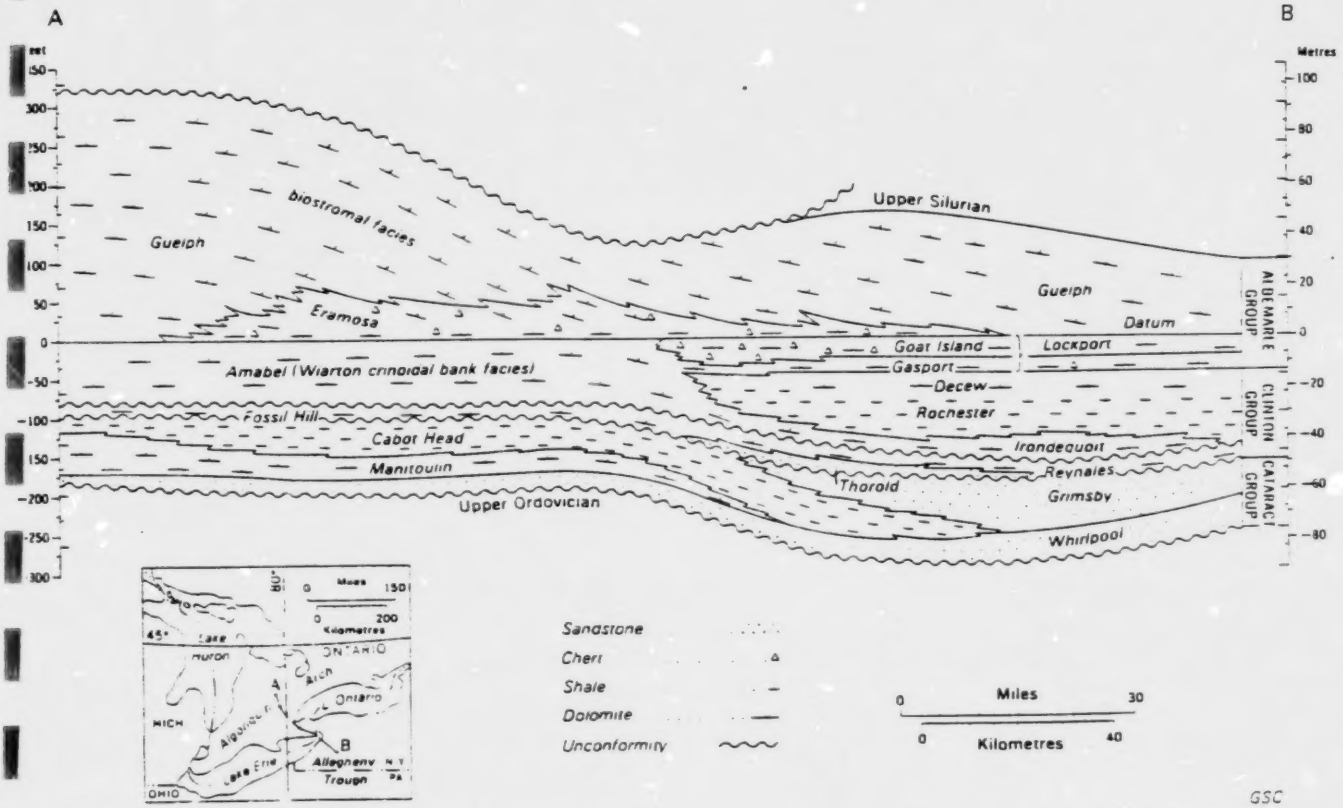


FIGURE VI-16. Cross-section of Lower and Middle Silurian strata, Algonquin Arch to northwestern Allegheny Trough, southwestern Ontario and New York (by B. V. Sanford).

From page 269, Sanford, 1976a,

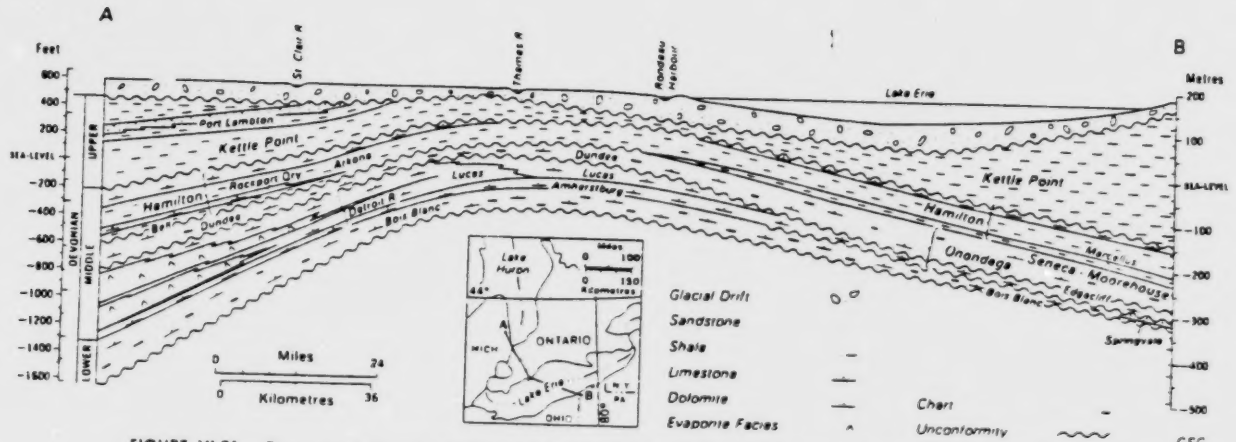
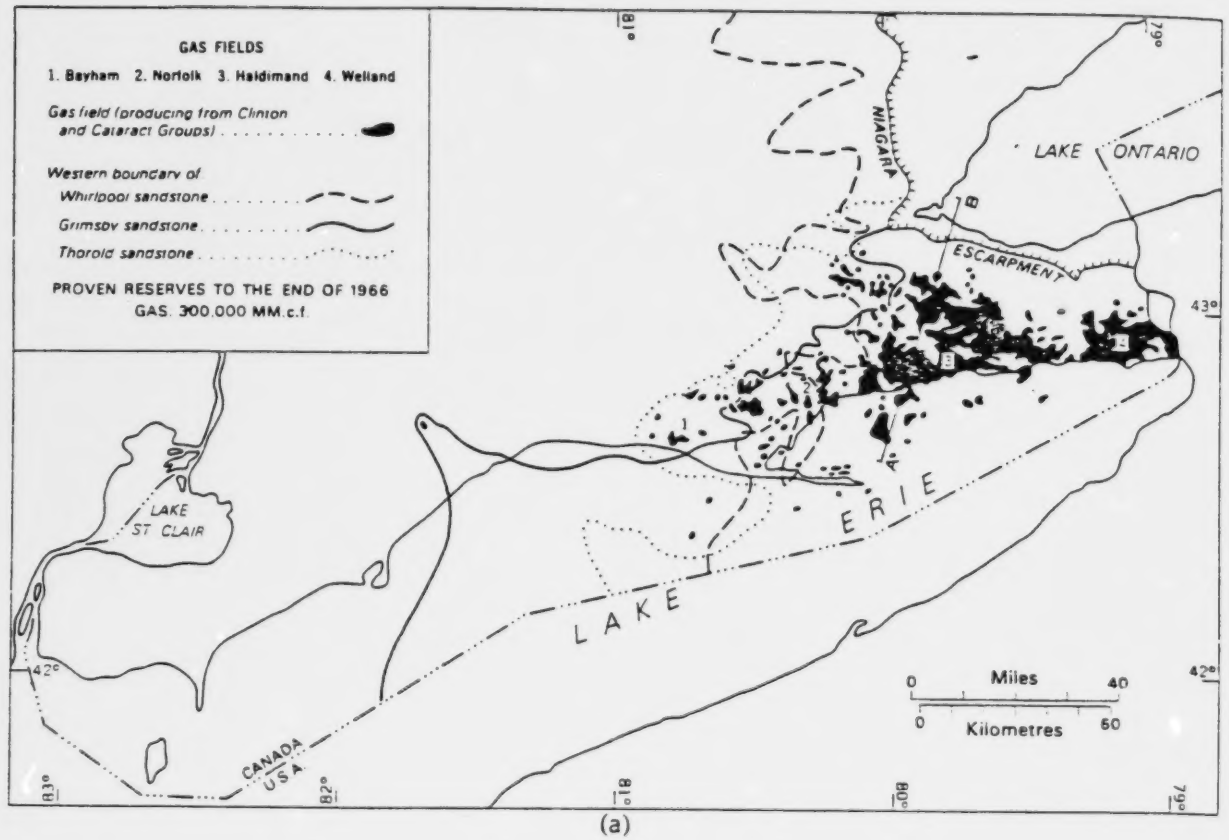


FIGURE VI-21. Cross-section through Devonian rocks of Algonquin Arch of southwestern Ontario (by B. V. Sanford).

From page 284. Sanford, 1976a.



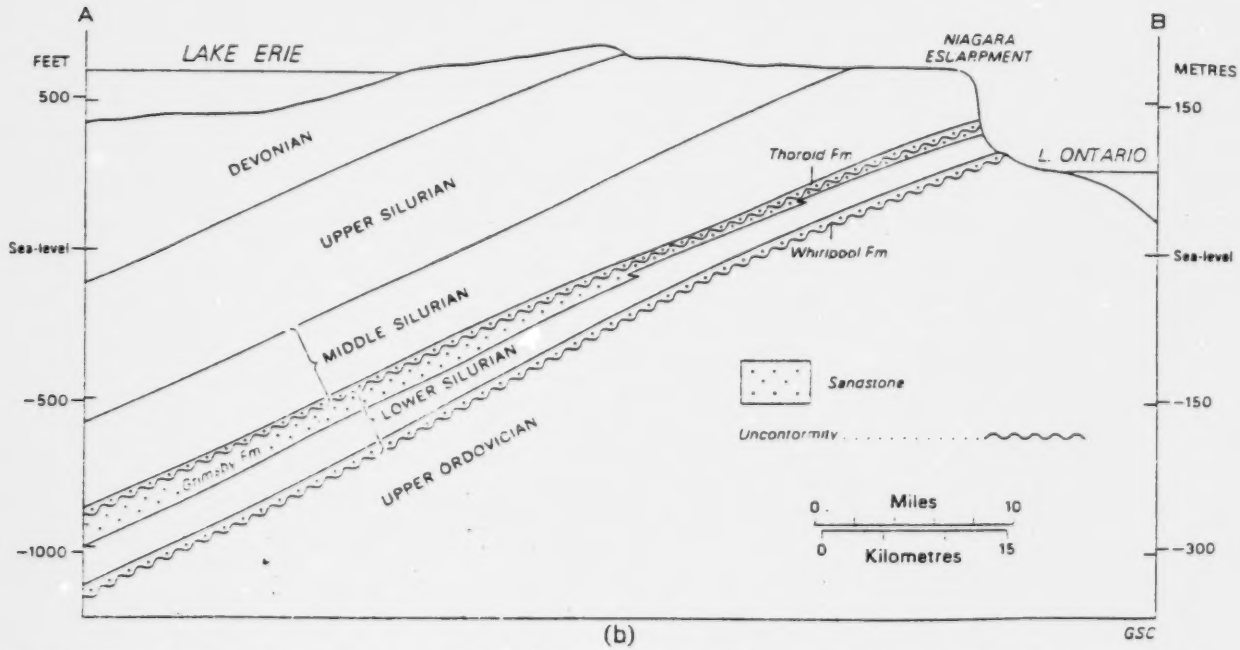
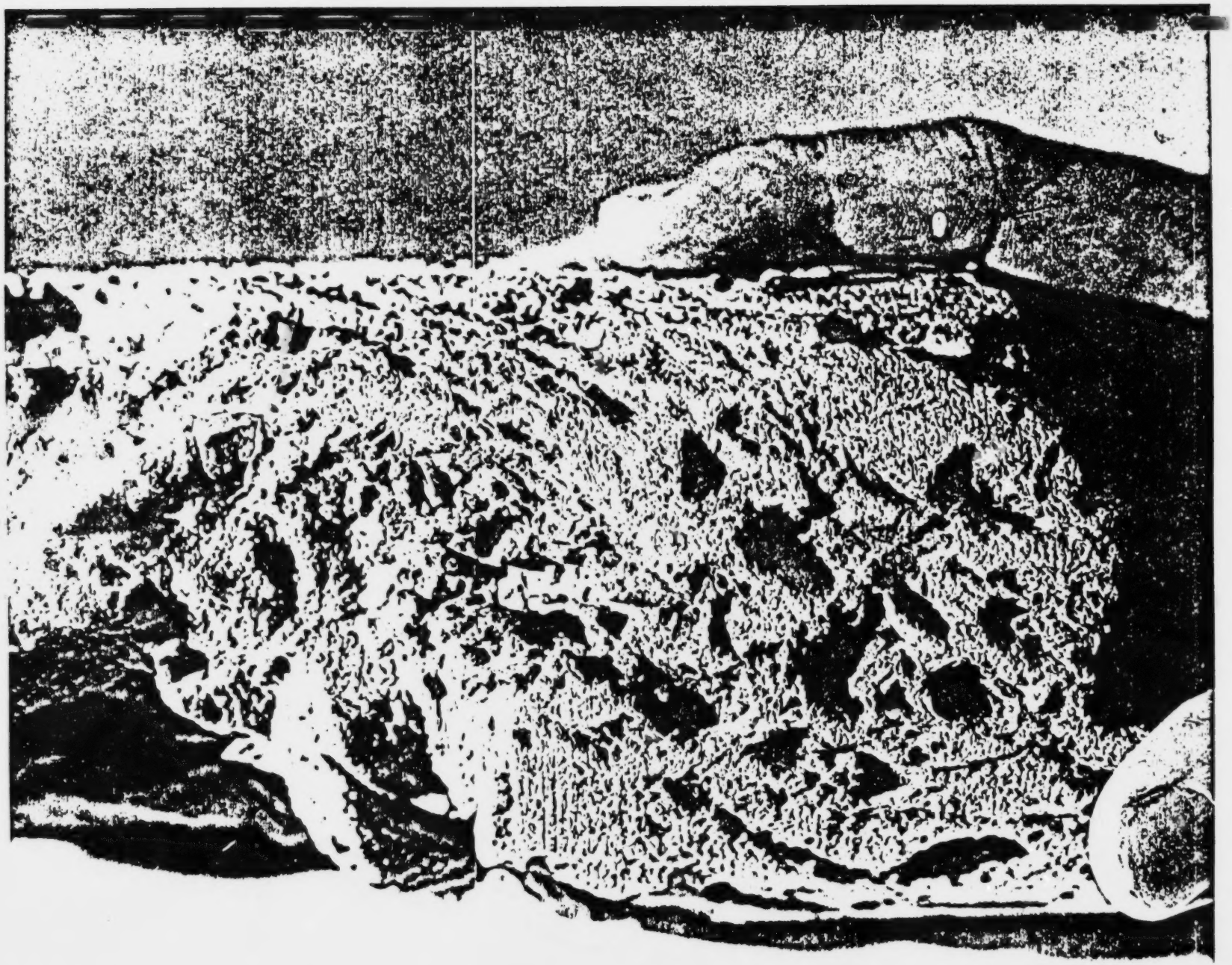
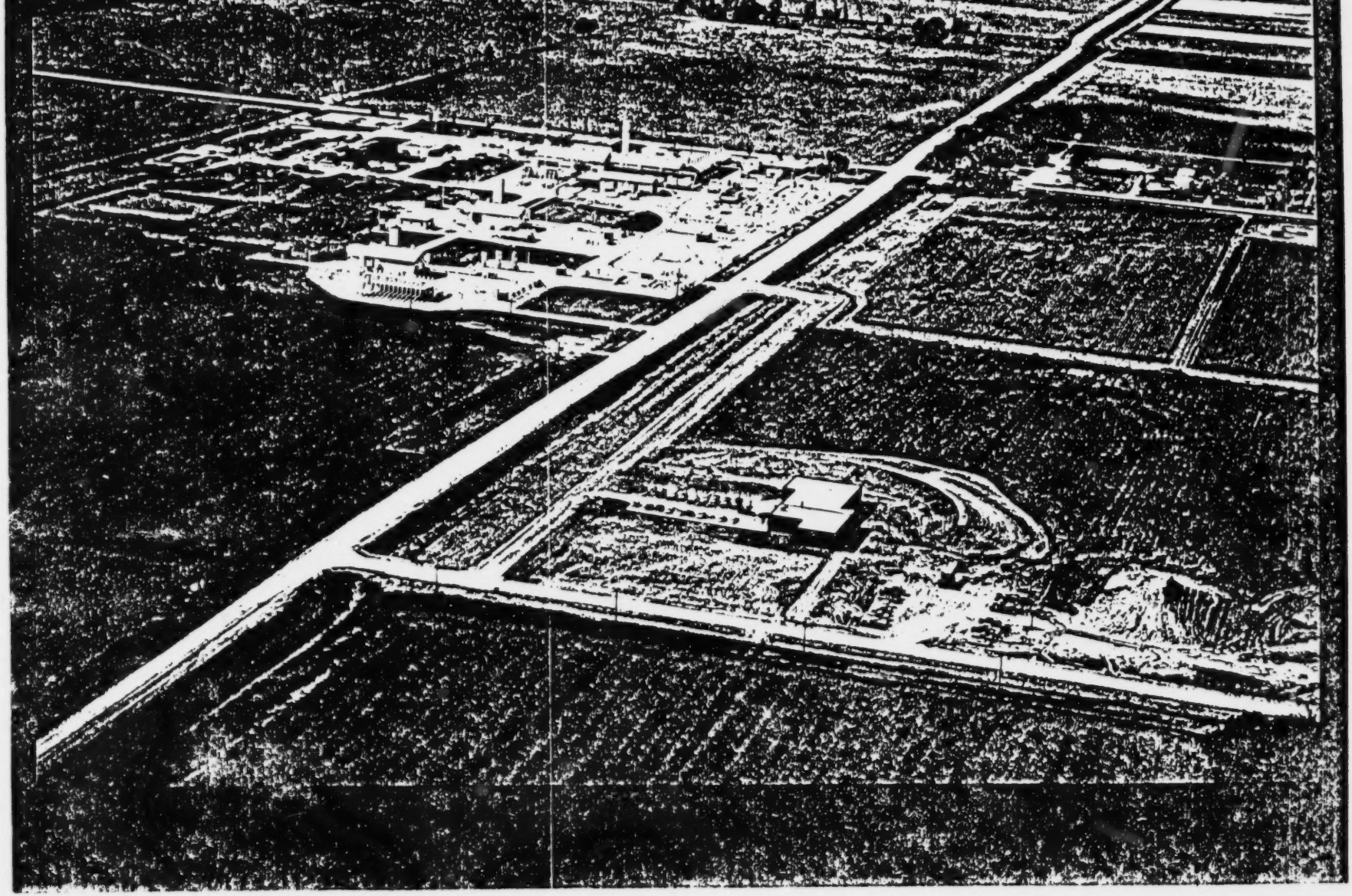


FIGURE VII-29. Gas fields in the Silurian Clinton and Cataract Groups (by B. V. Sanford). (a) Distribution of fields and limits of producing sandstones. (b) Cross-section along line A–B.

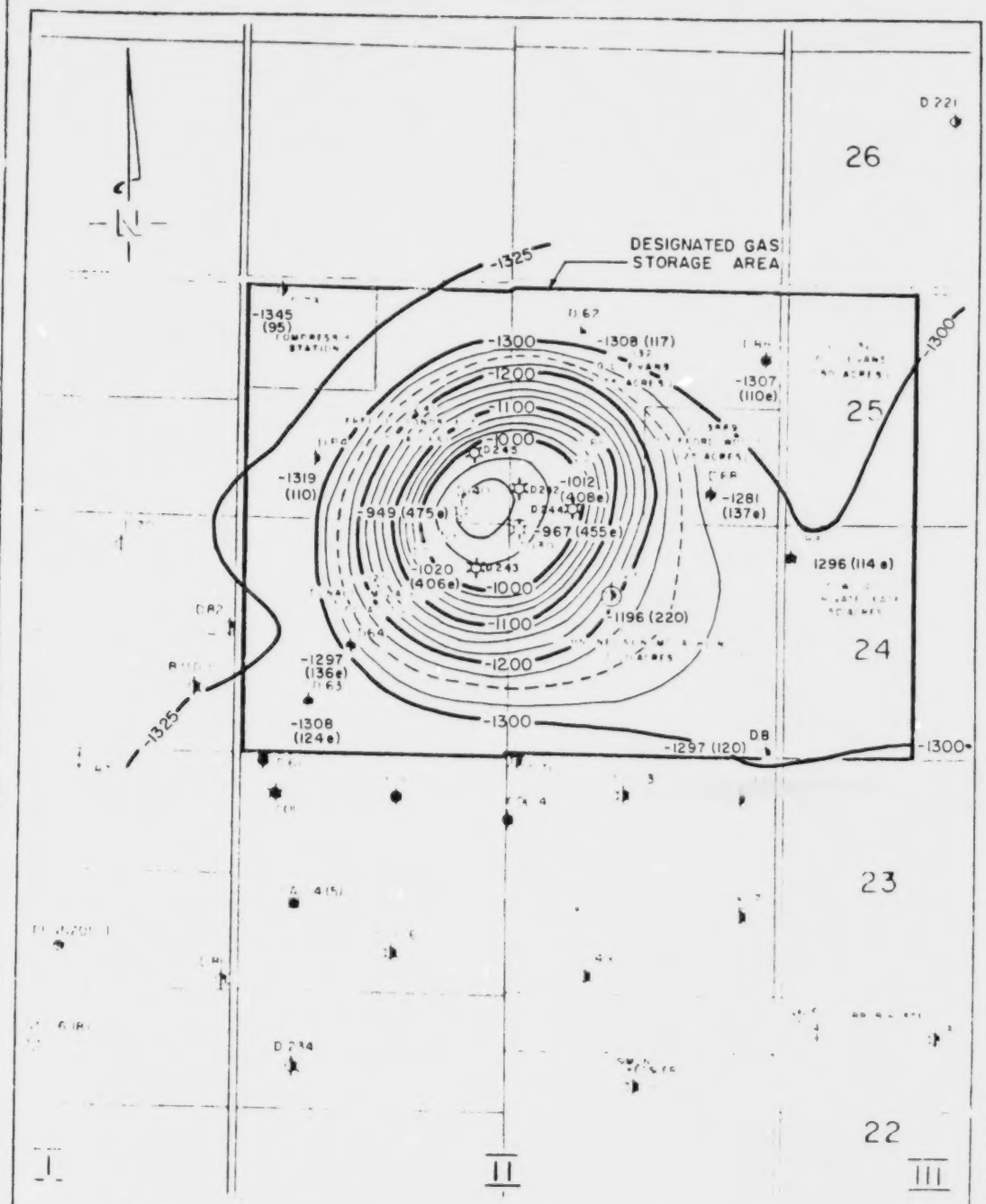
From page 352. Sanford, 1976 b.



Reef Rock Core Showing Porosity



Aerial View of Dawn Compressor Station - Union Gas



LEGEND

- GAS WELL
- GAS WELL, OIL SHOW
- OIL AND GAS WELL
- OIL WELL, GAS SHOW
- OIL AND GAS SHOW, ABANDONED
- GAS SHOW, ABANDONED
- OIL SHOW, ABANDONED
- SMALL OIL SHOW ABANDONED
- DRY HOLE
- SHOW OF GAS, SMALL SHOW OIL, ABANDONED
- OIL WELL, GAS SHOW, ABANDONED

D 85 (WELL NO.)

-1012 (ELEV. TOP GUELPH-LOCKPORT)

(4088) ISOPACH GUELPH-LOCKPORT

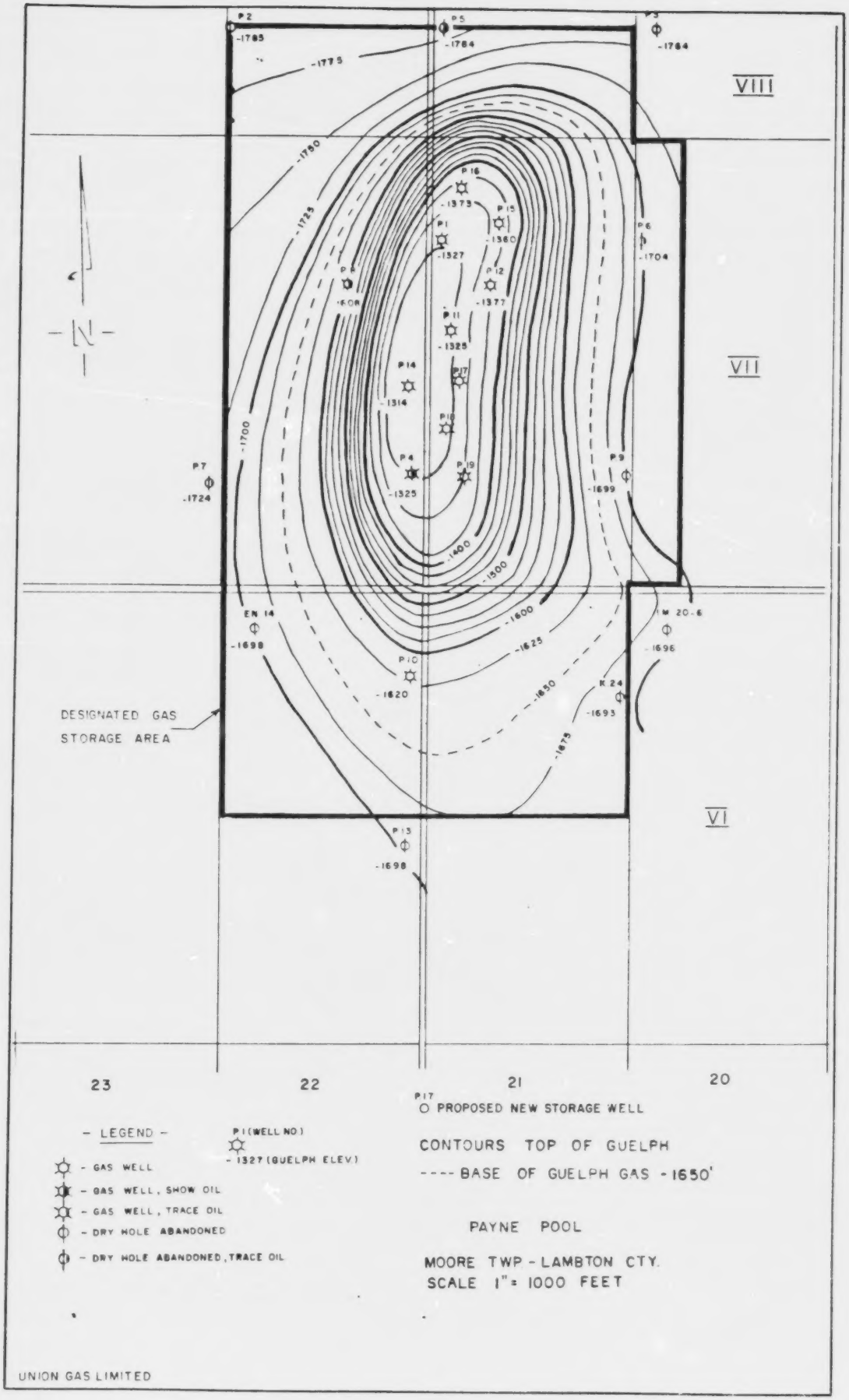
e = ESTIMATED

CONTOURS TOP GUELPH-LOCKPORT

---- BASE OF GUELPH GAS -1250'

UNION GAS LIMITED

CHATHAM, ONTARIO.
APRIL, 1986


P2
-1785
P5
-1784
P3
-1784
-1775
VIII
-1750
P16
-1373
P15
-1360
P1
-1327
P6
-1704
P8
-1508
P12
-1377
P11
-1325
VII
P14
-1314
P17
P10
-1700
P7
-1724
P4
-1325
P19
P9
-1699
-1400
-1500
-1600
-1625
EN 14
-1698
IM 20-6
-1696
P10
-1620
-1650
K 24
-1693
-1675
DESIGNATED GAS
STORAGE AREA
VI
P13
-1698
23
22
21
20
P17
O PROPOSED NEW STORAGE WELL
- LEGEND -
P1 (WELL NO.)
-1327 (GUELPH ELEV.)
- GAS WELL
- GAS WELL, SHOW OIL
- GAS WELL, TRACE OIL
- DRY HOLE ABANDONED
- DRY HOLE ABANDONED, TRACE OIL
CONTOURS TOP OF GUELPH
---- BASE OF GUELPH GAS -1650'
PAYNE POOL
MOORE TWP. - LAMBTON CTY.
SCALE 1" = 1000 FEET
UNION GAS LIMITED

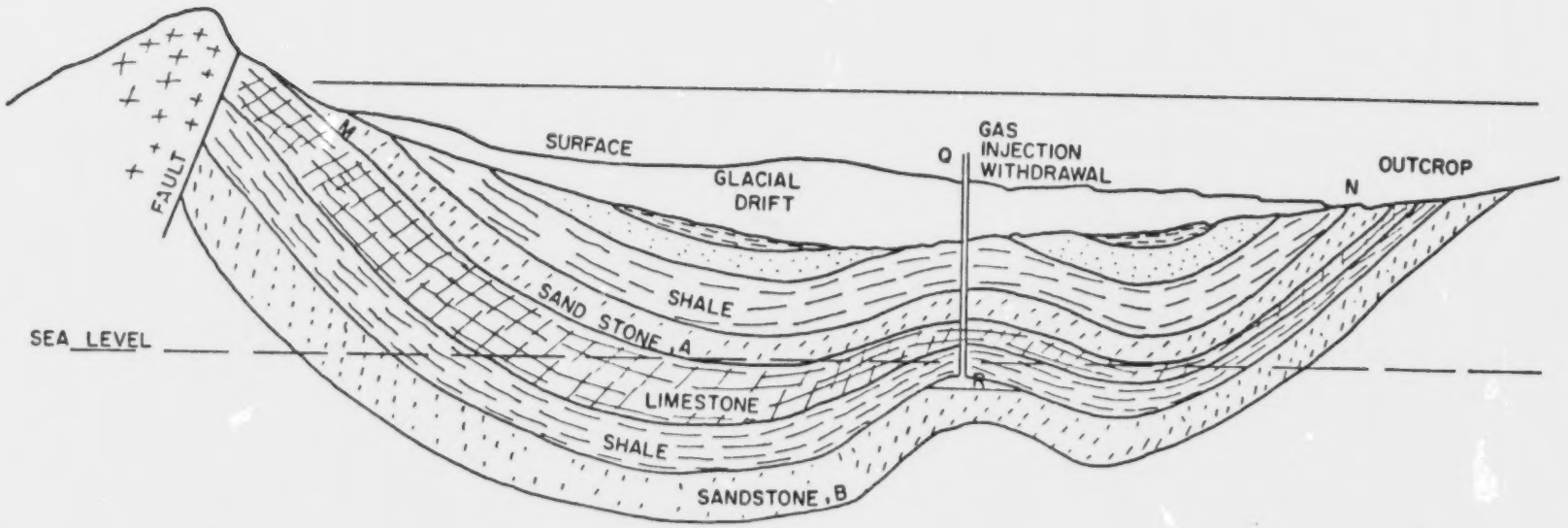


Figure 1-10. Section showing blanket water-bearing sandstones known as aquifers

Katz and Coats, "Underground Storage of Fluids, 1968.

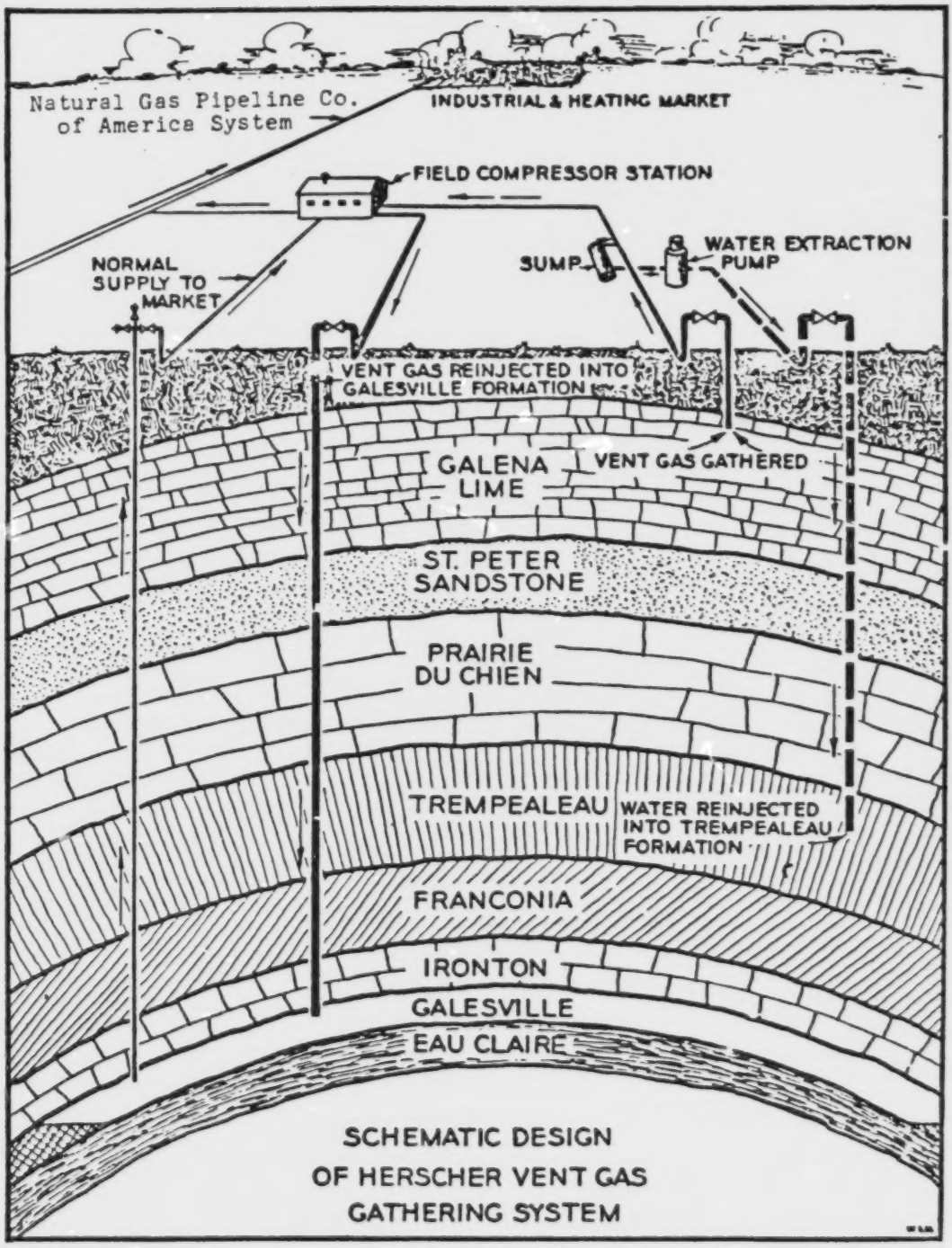


Figure 1-12. Artists conception of vent gas cycling system at Herscher. (1-31)

Katz and Coats, "Underground Storage of Fluids, 1968

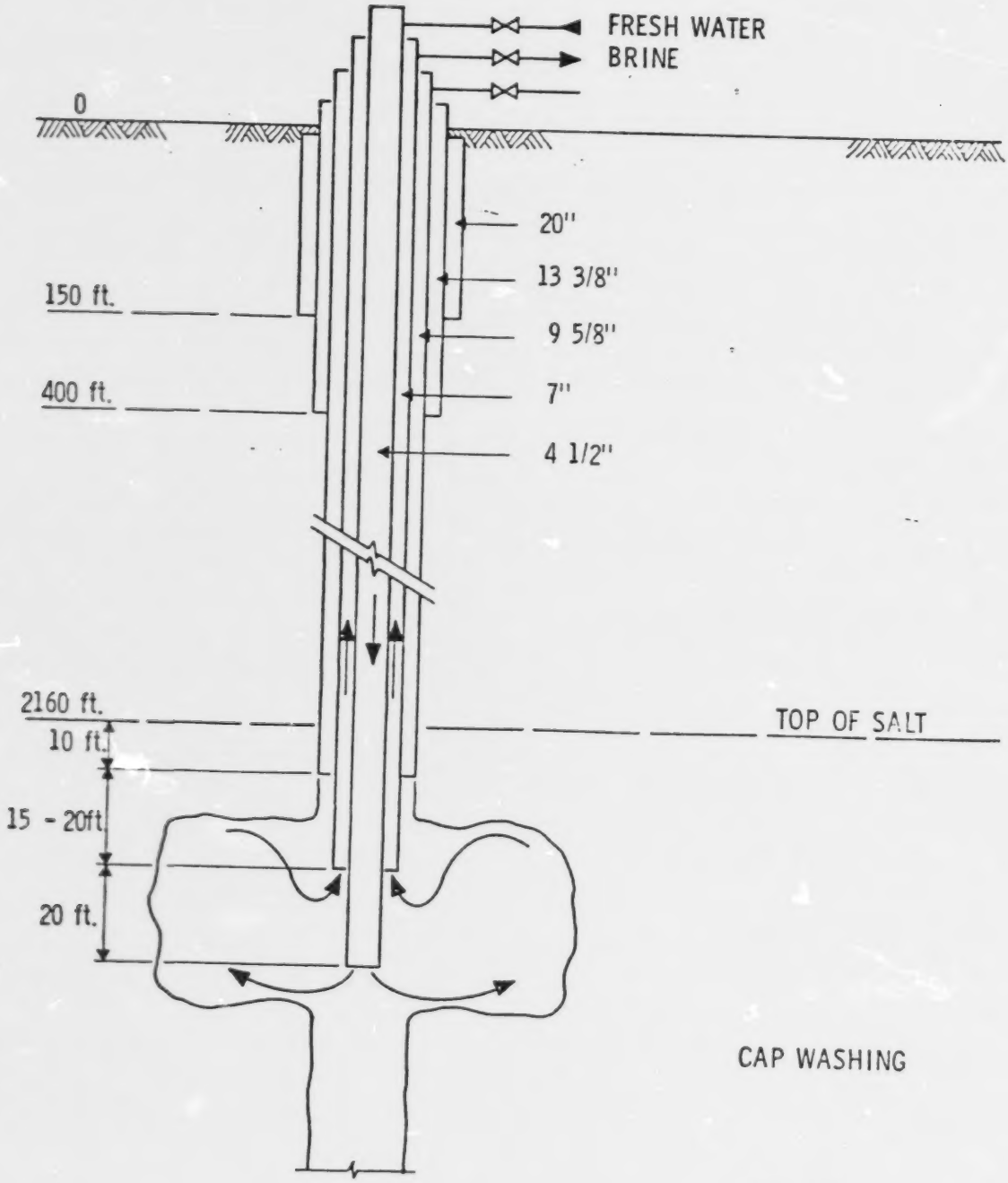
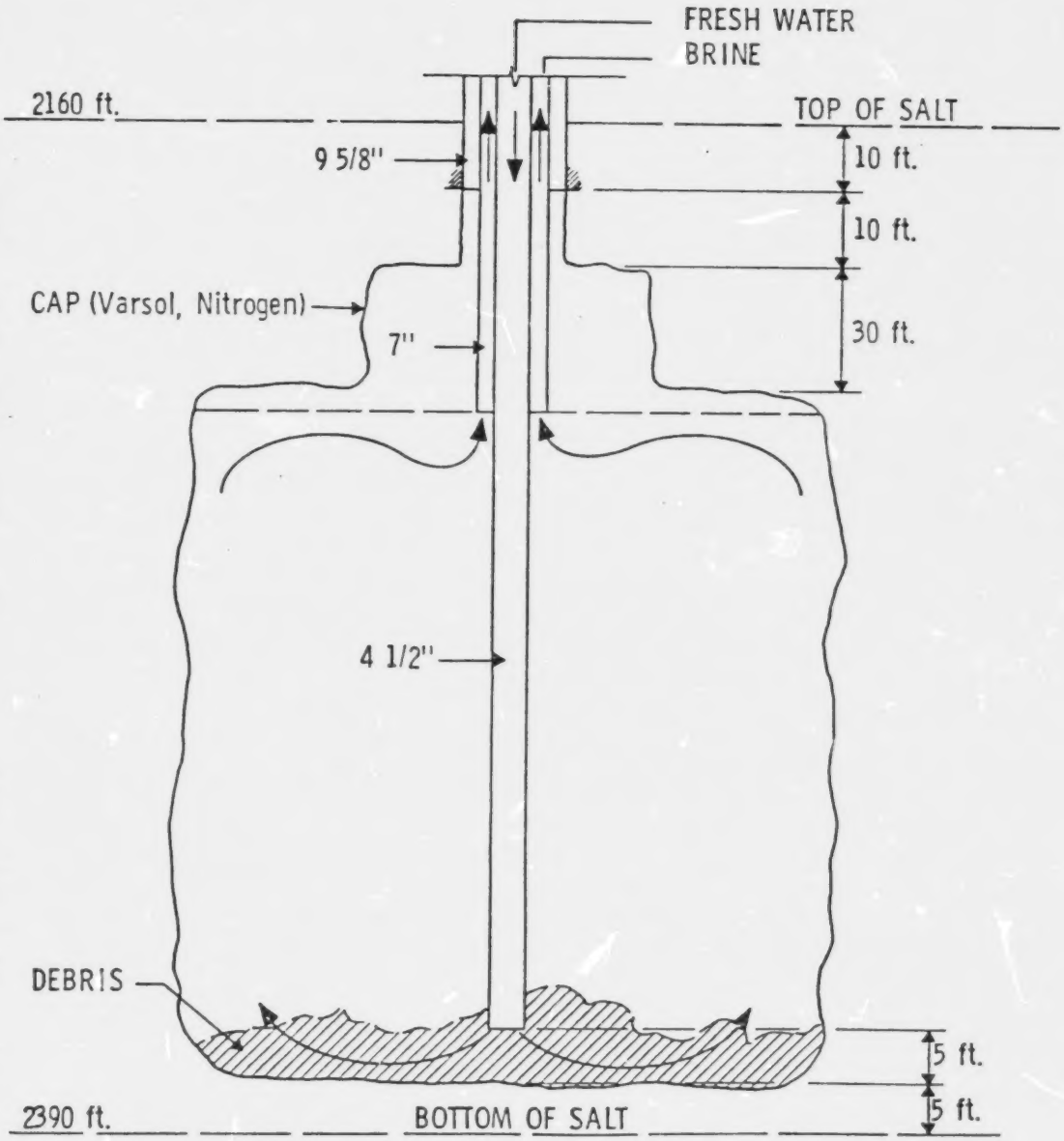


Figure 1

H.J. Honig Paper "L.P.G. Storage in Salt Caverns in Sarnia Area," O.P.I. Annual Report, 1969.

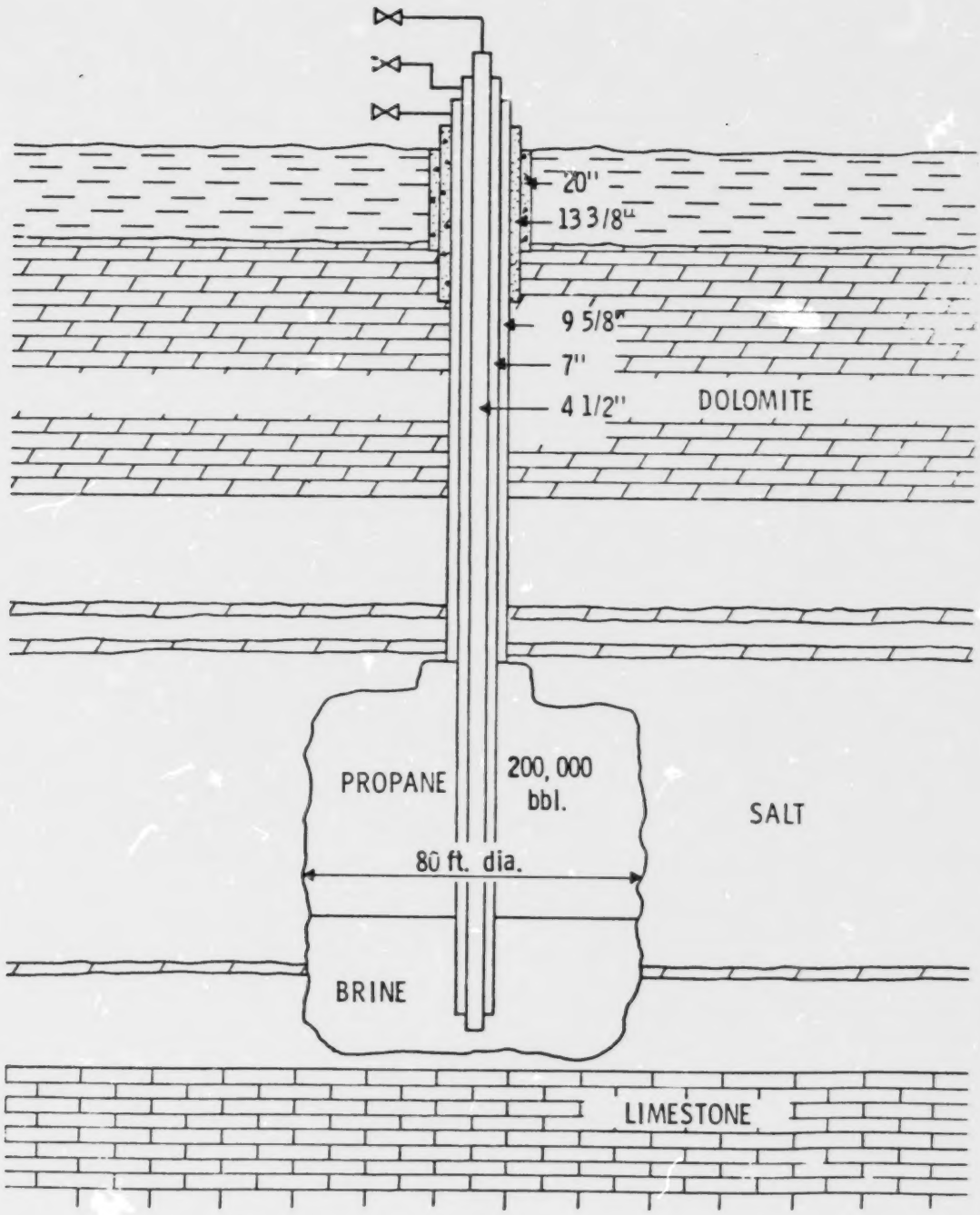


CAVERN WASHING

Figure 2

H. J. Honig Paper, "L.P.G. Storage in Salt Caverns in Sarnia Area", O.P.I. Annual Report, 1969.

Figure 3



H.J. Honig Paper, "L.P.G. Storage in Salt Caverns in Sarnia Area," O.P.I. Annual Report 1969.

MELVILLE STATION

(In a Product Removal Mode)

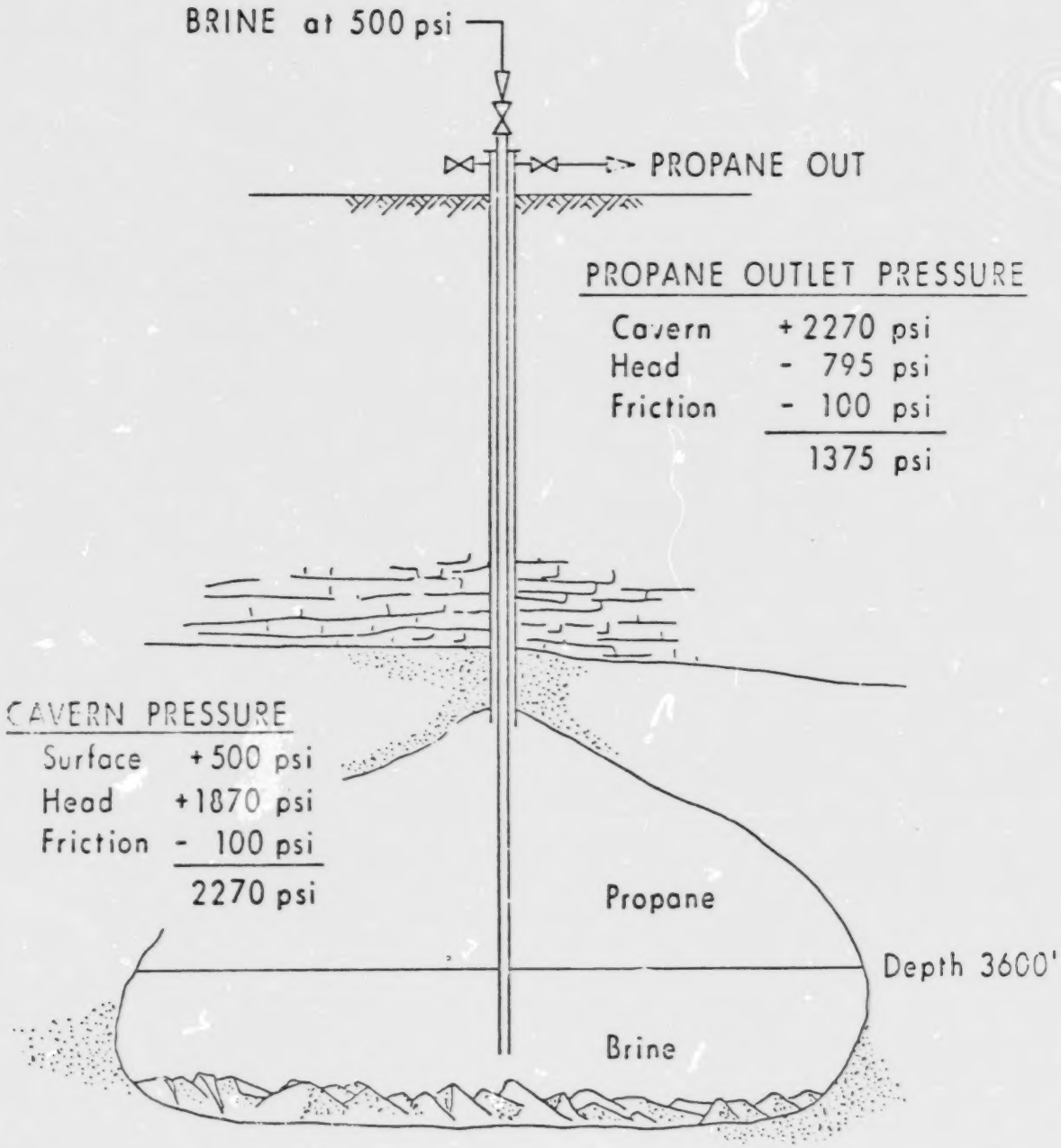
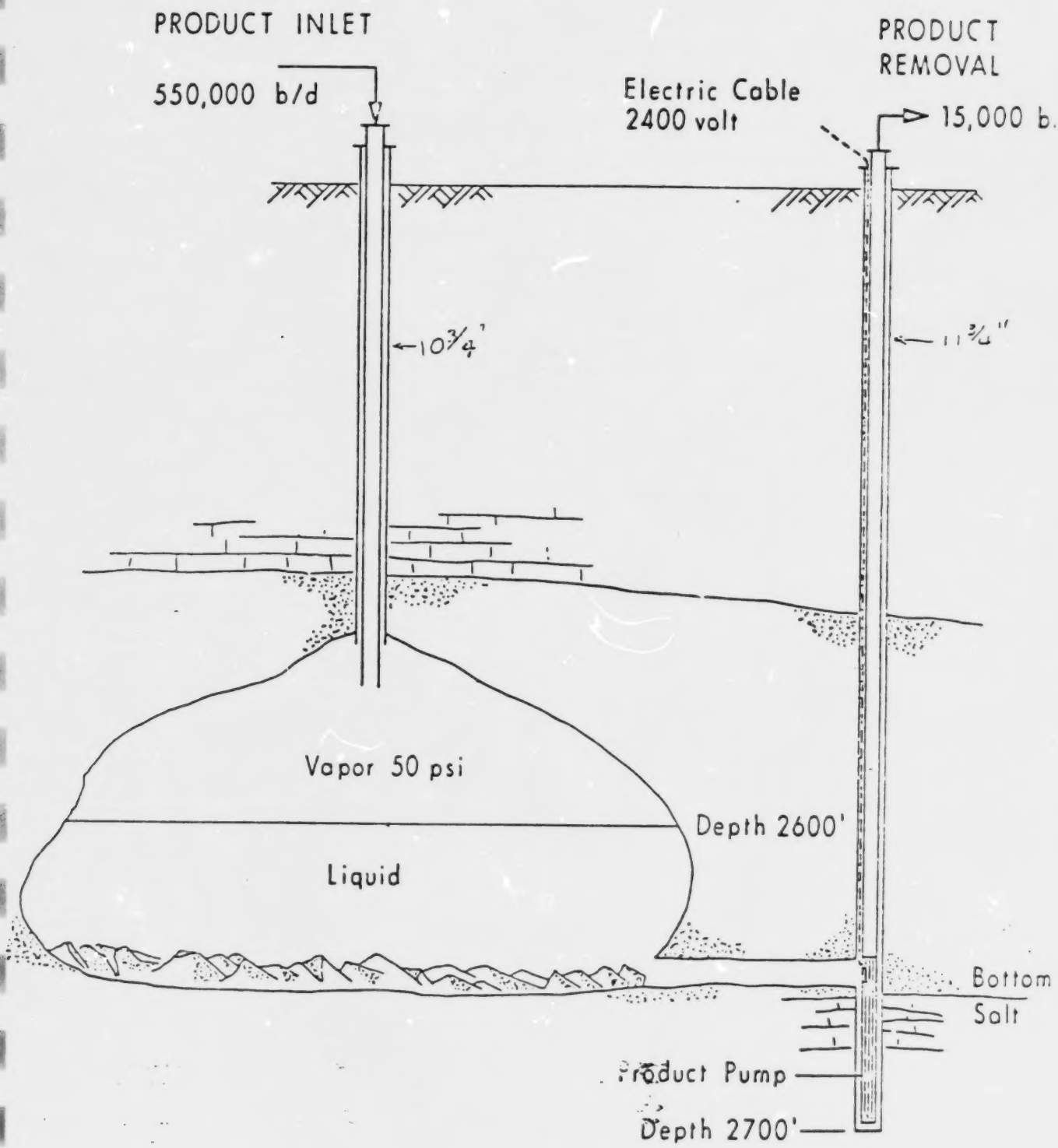


FIG. 3

R.W. Temple, Paper, "Storage of Large Volumes of Liquefied Petroleum Gases," O.P.I. Annual Conference, 1973.

SARNIA STATION
(Raw Product Coverns)



R.W. Tample, Paper "Storage of Large Volumes of Liquefied Petroleum Gases," O.P.I. Annual Conference, 1973.

Fig 7

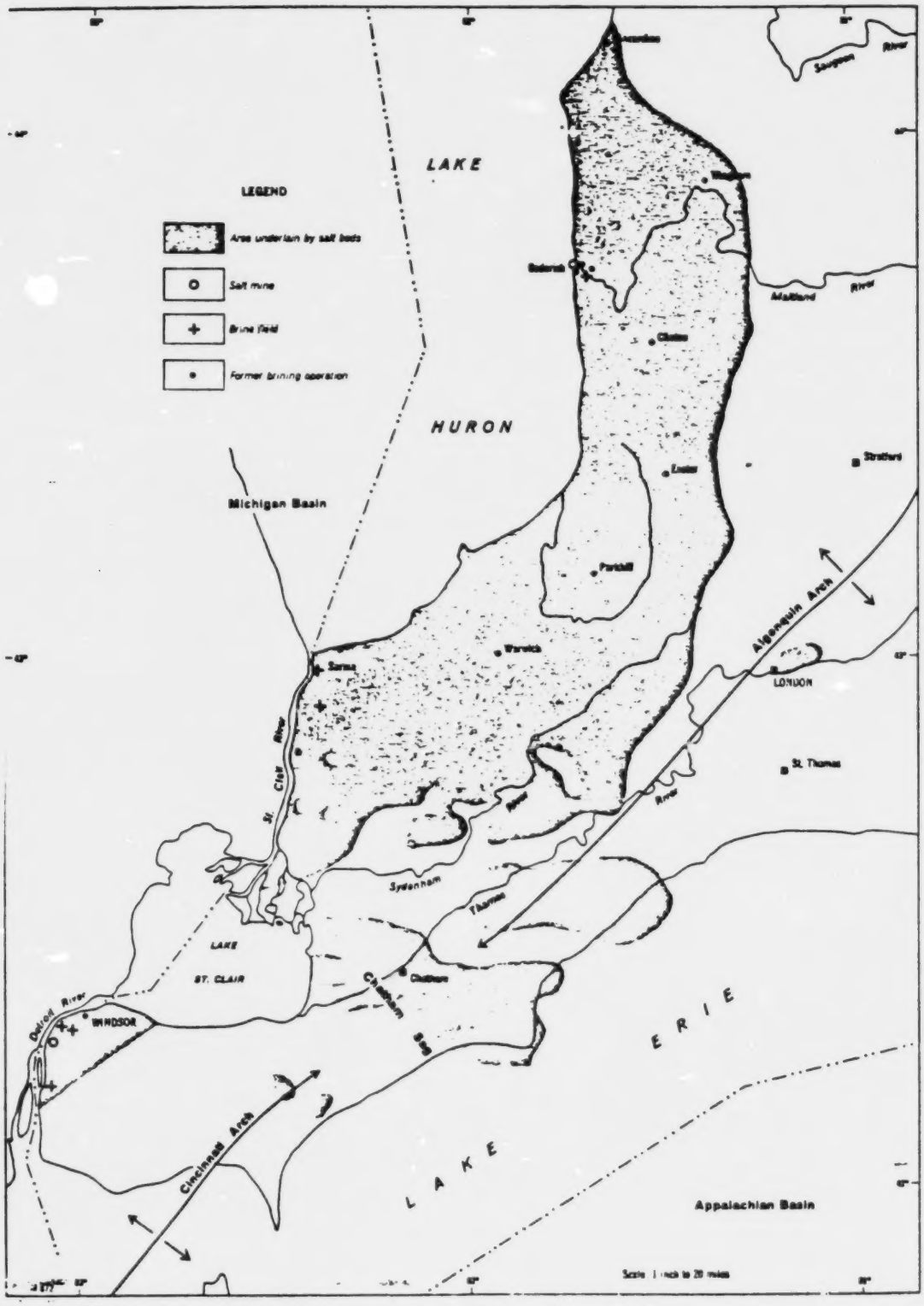


Figure 2 – Distribution of salt in southwestern Ontario.

D.F. Hewitt, O.D.M., "Industrial Mineral Report No. 6, Salt in Ontario," 1962.

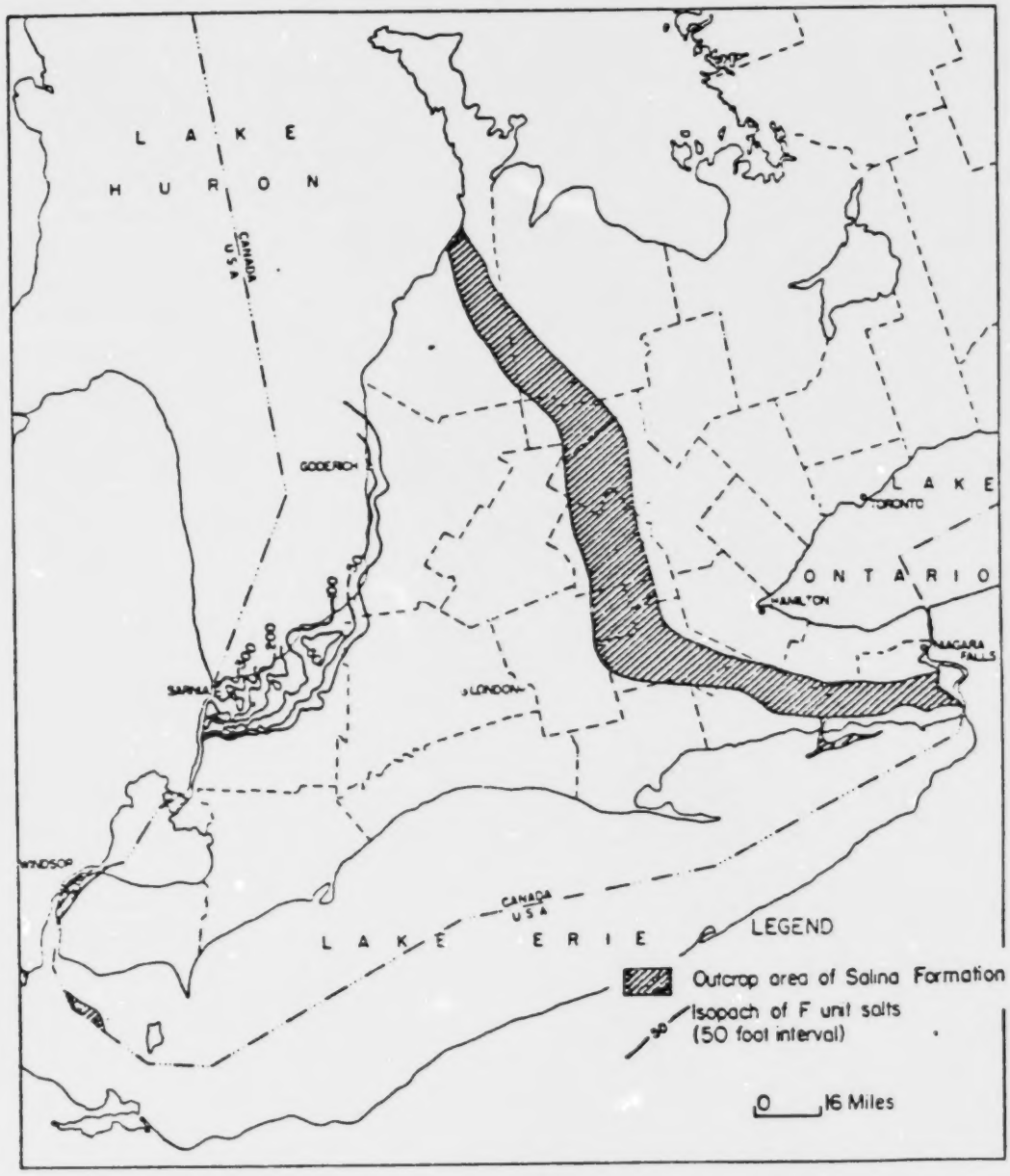
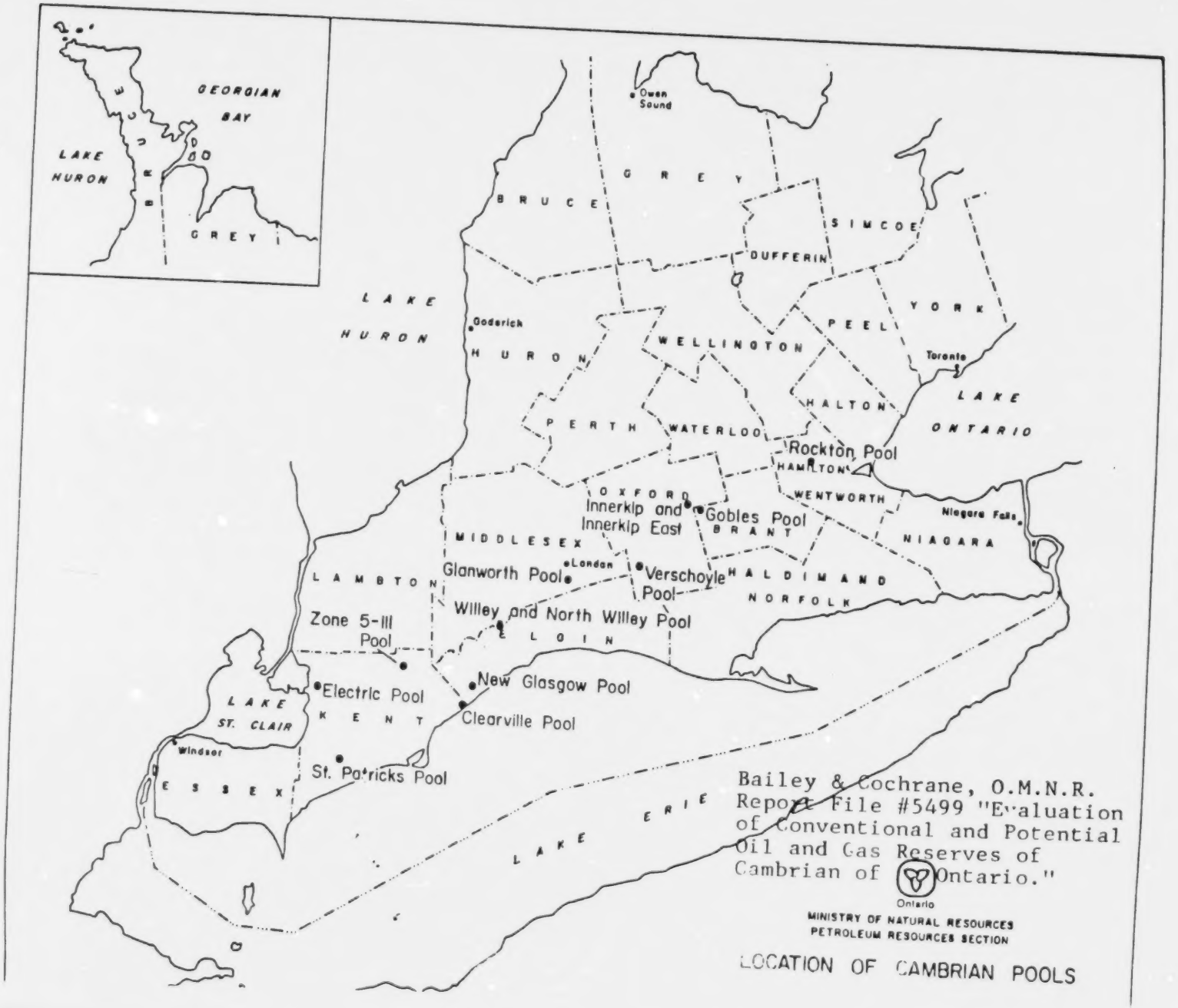


Figure 37: Isopachous map of Salina F unit salts, southwestern Ontario

B.V. Sanford Paper, "Silurian of Southwestern Ontario"
O.P.I. Annual Conference, 1969.



Bailey & Cochrane, O.M.N.R. Report File #5499 "Evaluation of Conventional and Potential Oil and Gas Reserves of Cambrian of Ontario."

Ontario
MINISTRY OF NATURAL RESOURCES
PETROLEUM RESOURCES SECTION

LOCATION OF CAMBRIAN POOLS

COMPARISON OF POTENTIAL RESERVE DATA WITH PUBLISHED DATA
FOR THE CAMBRIAN IN ONTARIO

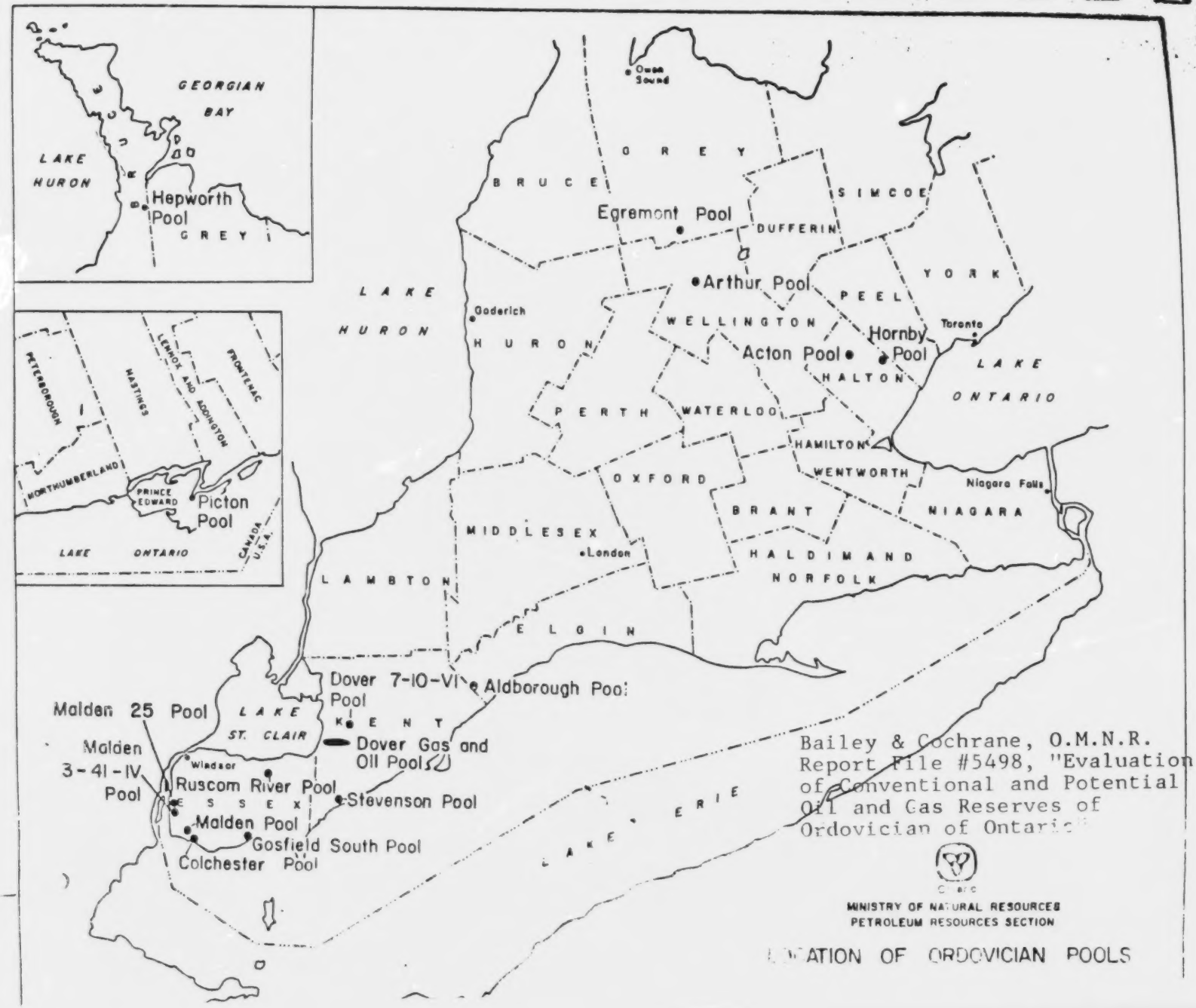
PARAMETER BASIN	R.B.HUTT ET.AL.1973 PUBLISHED DATA	PRESENT STUDY DATA	CHANGE
TOTAL ROCK VOLUME (KM3)			
MICHIGAN	533.5	2317	
APPALACHIAN	1838.2	1761	
TOTAL	2371.7	4078	**
PROVEN RECOVERABLE OIL RESERVES (M3)			
TOTAL	1,269,840	909,536	-28.4%
PROVEN RECOVERABLE GAS RESERVES (1000M3)			
TOTAL	96,825	469,644	+4.85
PROVEN OIL RECOVERY FACTOR (M3/KM3)			
APPALACHIAN	690.4	516.5	-25.2
PROVEN GAS RECOVERY FACTOR (1000M3/KM3)			
APPALACHIAN	52.7	266.7	+5.05
PROVEN GAS-OIL RATIO	76.2	516.4	+6.78
POTENTIAL OIL RESERVES (1,000,000M3) ***			
MICHIGAN	---	10.49	
APPALACHIAN	26.76	7.22	
TOTAL	26.76	17.71	
POTENTIAL GAS RESERVES (1,000,000M3) ***			
MICHIGAN	-----	4,305.6	
APPALACHIAN	4,637.3	1,965.4	
TOTAL	4,637.3	6,271.0	+1.35
POTENTIAL OIL RECOVERY (M3/KM3) ***			
MICHIGAN	-----	4,527.4	
APPALACHIAN	14,571.0	4,099.9	
AVERAGE	14,571.0	4,341.7	
POTENTIAL GAS RECOVERY (1000M3/KM3) ***			
MICHIGAN	----	1,858.3	
APPALACHIAN	2,522.7	1,116.1	
AVERAGE	2,522.7	1,537.8	

** DIFFERENT ISOPACH INTERVAL
*** R.B. HUTT ET AL DISCOUNTED TO ZERO THE POTENTIAL RESERVES IN THE MICHIGAN BASIN.

REVISION ROC 1924 07 03

Bailey & Cochrane, O.M.N.R. Report File #5499, "Evaluation of Conventional and Potential Oil and Gas Reserves of Cambrian of Ontario".

FIGURE C-4



Bailey & Cochrane, O.M.N.R. Report File #5498, "Evaluation of Conventional and Potential Oil and Gas Reserves of Ordovician of Ontario"

MINISTRY OF NATURAL RESOURCES
PETROLEUM RESOURCES SECTION

LOCATION OF ORDOVICIAN POOLS

INDEX MAP
MICHIGAN BASIN GEOLOGICAL SOCIETY SYMPOSIUM
OIL AND GAS FIELDS OF MICHIGAN

APPENDIX III

UNION GAS RATE DETERMINATION

In the analysis below, reference is made to the financial schedules in the cost allocation process. These are taken from exhibits filed by Union Gas in December, 1985 in support of its rate application under E.B.R.O. 405-2 before the Ontario Energy Board. The schedules cover the test year ended March 31, 1987. The amounts are based on estimates developed in Union's forecast system.

For the functionalization step referred to above, the following relevant schedules are employed:

Exhibit G2.1 - Average investment in Property Plant and Equipment by functions (3 pages)

Exhibit G3.1 - Average balance of Accumulated Depreciation by functions (2 pages)

The accounts represented in these schedules are the two major items included in the utility rate base. The rate base is summarized on Exhibit G1 (revised) and totals $895 million.

This is the starting point for preparation of the cost allocation study. The rate base is listed on Exhibit K3.2.1, column (e) and at this stage shows the investment directly attributable to each function. Column (f) provides the related taxes and return resulting from the rate base for the same functions.

On Exhibit K3.1 these financial costs are added to property taxes and depreciation to arrive at total investment carrying costs by functions (column (d)). Columns (e) and (f) show the transfer of indirect costs of the direct functions. The indirect costs are shown in column (e) and the results of the transfers to direct functions are shown in column (f).

For operating and maintenance expenses, the forecast level by functions is provided on Exhibit F6.1.

The expenses are also listed on Exhibit K3.4 in column (a). The transfer of indirect costs to direct functions is shown in columns (d) and (e). Administrative expense is an example of indirect costs which must be allocated to direct functions such as storage, distribution and transmission.

Investment carrying costs and operating and maintenance expense are brought together on Exhibit K4.1, in column (a). These costs, along with cost of gas purchases, result in total cost of service, shown on line 13 as $1,450 million. Up to this point the process involves determination of the components of cost of service by function.

Exhibit K4.1 indicates the results of classifying functional cost levels into cost categories. These categories recognize cost incurrence and provide the amounts to be charged to rate classes, based largely on consumption of gas and utilization of facilities.

The main bases of cost allocation are:

Commodity Related - volume consumption for the annual period.

Capacity - system facilities utilized, usually to meet peak day requirements. Under this heading there are several subsidiary categories.

Storage - space

Costs involved in holding summer deliveries in excess of average use over to the winter season. The allocation method is the ratio of the excess of customer class winter use over winter average day consumption compared to a similar factor for the total system.

Storage - deliverability

Facility costs, primarily compression, for capacity to meet seasonal peak period requirements. The allocation method followed by Union is the relationship of the average of the three day peak over average day for the class compared to the system.

Transmission - capacity costs associated with delivery of gas to Union's market. The basis of allocation of costs is described as the modified partial plant method. This method rates class use on a priority basis with consumption on peak days carrying more responsibility for costs than off-peak days of use.

Distribution - this involves capacity to meet customer demand and also access to customers. Allocation of costs is based on the relationship of peak day use.

Customer - customer costs are those which result directly from the number of customers served. Various methods are recognized in the allocation process, such as value of plant and number of customers by rate class.

Direct Assignment - costs which are directly attributable to specific rate classes.

The system costs categories summarized on Exhibit K4.1 are brought forward in total to Exhibit K5.1.1. These total dollars are then allocated to the sales classifications, such as General Service, Interruptible and Seasonal.

Exhibits K5.1.2 and .3 show the units for each sales classification that are used to allocate system costs.

Storage and Transmission Operations

Referring again to Exhibit K4.1, cost of service is indicated by functions, including storage and transmission. These have been further classified into cost categories.

These amounts for storage and transmission are brought forward to Exhibit K6.1 and 2 where amounts by cost categories are detailed by asset type and operating activities. These amounts are after cost transfers such as that to recognize use of the Dawn compressor station for transmission purposes as well as storage.

Allocation units for the cost categories within the storage and transmission functions are indicated on Exhibit K6.3. These are applied to calculate unit costs shown on this Exhibit.

The allocation units are:

Storage - space - working storage capacity
- demand - maximum day use
- commodity - annual volume handled

Transmission demand - maximum day kilometres

The basic unit costs developed on K6.3 are then brought forward as storage and transportation rates on Exhibit K6.4 and are then applied to the billing units for each utility to arrive at the revenue requirement based on cost of service in column (f).

A summary of Union storage and transmission costs, based on 1987 test year estimates, is provided on Tables III-1 to III-4.

For the 1987 test year Union calculates system cost of service of $1,450 million. After deducting cost of gas, a balance of $349 million remains. This represents the investment carrying costs

TABLE III-1

Summary of System Plus Storage and Transmission
Cost of Service for Union Gas Limited for Year
Ended March 31, 1987

	$ Millions
Total system cost of service	1,450
Less cost of gas	1,101
Balance	349
Consists of	
Investment carrying costs	230
Operating and maintenance expense	119
	349

Storage and Transmission

	Storage	Transmission	Total
Investment carrying costs	45	53	98
Operating maintenance expenses	10	12	22
Total	55	65	120
Transfers and adjustments	(8)	8	-
Balance	47	73	120
Revenue from Storage and Transportation			
Utility customers, Rates M12 and M13	10	43	53
Balance of costs to sales customers	37	30	67

TABLE III-2

Unit Costs of Storage by Cost Categories
(Exhibit K6.2)
Forecast Year Ended March 31, 1986

Cost Category	Cost of Service ($000)	System Allocation Units ($10^6 m^3$)	Unit Cost ($/10^3 m^3$)
Space	6,348	2661.3	.199 per month
Demand	15,156	36.252	34.839 per month
Commodity	3,014	2052.2	1.469
Total Costs	24,518		
Annual Volume		2052.2	11.947

TABLE III-3

Union Gas Limited
Forecast Year Ended March 31, 1987
Allocated Storage Costs

	Cost ($000)	Allocation Units (10^6m^3)	Unit Cost ($/$10^3m^3$)	($/Mcf)
Average Cost of Union Gas Storage for Other Utilities				
Consumers' Gas	5,065	720.3	7.032	.1992
Gaz Metropolitan	1,886	550.1	3.429	.0971
Northern & Central	808	200.0	4.04	.1145
Kingston P.U.C.	56	14.0	4.00	.1133
Total storage under Rate 12	7,815	1,484.4	5.265	.149
Other storage services	2,249	-	-	-
Total to other utilities	10,064	1,484.4	6.780	.192
Balance for Union Sales Customers				
Share of allocated costs (U)	14,454	567.8	25.456	.721
Sub-total	24,518	2,052.2	11.947	.338
Space costs directly for Union (U)	23,245	567.8	40.939	1.160
Total	47,763	2,052.2	23.274	.659
Total Union customers (U)	37,699	567.8	66.395	1.881

TABLE III-4

Allocation of Storage Fixed Costs to Union
Sales Classification, After Costs Have Been
Assigned to Storage and Transportation Customers
March 31, 1987
($000)

	Rate Schedule	Fixed Storage Costs			Annual Sales Volume ($10^3 m^3$)
		Space	Deliver-ability	Total	
Costs allocated to:					
Firm Sales					
General Service	M2				
Residential		8,417	3,676	12,093	1,486
Non-contract comm. and industrial		8,511	3,684	12,195	1,817
Sub-total		16,928	7,360	24,288	3,303
Firm indust. and comm.	M4	355	139	494	503
Spec. Large Volume, firm	M7	879	350	1,229	1,410
Large wholesale	M9	919	350	1,269	234
Small wholesale	M10	8	4	12	1
Non-Firm Sales					
Interruptible and Commercial	M5A	1,395	170	1,565	703
Special Commercial Large Volume	M7	790	164	954	1,168
TOTAL		21,274	8,537	29,811	7,330

and operating and maintenance expenses relating to the facilities dedicated to utility service. Of this amount $47 million represents the fixed and operating costs of storage activities.

Based on a detailed cost allocation, rates for storage service provided under long term contracts with utilities, such as Consumers' Gas, Northern and Central Gas, and Gaz Metropolitan generate annual revenue of $10 million. After crediting this revenue and transferring storage costs to other functions which arise from multi-functional plant, such as the Dawn compressor station, fixed costs remaining and recoverable from Union's sales customers amount to $30 million. This is made up of about $21 million for the Space function and $9 million for Deliverability: these two items represent the cost categories applicable to the storage operation for Union's sales customers.

Of the total fixed storage costs of $29.8 million, the amount allocated to General Service is $24.3 million, or 81.5%. This amounts to $7.35 per 10^3m^3.

The revenue forecast based on sales rates requested by Union is about $220 per 10^3m^3 for General Service customers. The cost for storage of $7.35 represents 3.3% of the total rates.

Exclusion of cost of gas from the comparison results in storage costs for General Service of $7.35 per 10^3m^3 compared to cost of service of about $69 per 10^3m^3, or 9.4%.

Transmission System Cost of Service

Union's investment in transmission plant at March 31, 1987, as forecast by Union in its rate filing, is $296.4 million. This is shown on Schedule 5, page 2 of Union's exhibits included in our storage analysis. Of this amount the cost of mains is $229.2 million,

compressor equipment is $19.1 million and measuring and regulating equipment is $34.5 million. The amount for compressor equipment excludes the cost of the Dawn station. This investment is shown in the storage function on Schedule 5, page 1 and totals $47.9 million. In the subsequent cost allocation steps, about 50% of the cost of this station is transferred to transmission.

On Schedule 5, page 2, line 7 of the storage analysis, Union calculates the average investment for transmission plant at March 31, 1986 and 1987 at $285.4 million for rate base purposes. This amount is introduced in the Cost Allocation Study on Schedule 16, page 15, line 4. After deductions for accumulated depreciation, a net plant balance is determined of $229.313 million. On Schedule 25 attached to this review, deferred taxes for transmission plant are deducted, a rate base is computed of $189.2 million. The composite rate of 19.9519% is then applied to determine income taxes and return. This amount, shown in column (f), line 4 of Schedule 25, page 2, is $37.7 million. On page 1 of this Schedule, property taxes and depreciation are added to result in total investment carrying cost of $53.4 million for transmission plant.

This amount is brought forward to Schedule 26, column (d) line 2. Operating and maintenance costs are added to arrive at total cost of service for all transmission lines. Transfers of cost of the Dawn compressor station from storage to transmission are shown on lines 6 and 7. Transmission costs are then segregated for the Dawn-Trafalgar system. The balance held in "Other" relates to transmission costs for other than the main line, such as systems serving Windsor and the line to Owen Sound. Total cost of service for transmission on the Dawn Trafalgar system is 41.0 million for the 1987 test year.

On Schedule 27 this amount and costs of the Dawn station are classified between "demand" and "commodity" cost categories in columns (g), (h) and (i).

These totals are then entered on Schedule 21 in the storage review where they are divided by forecast allocation units to arrive at unit billing rates. These rates are applied to the billing units for each of the other utilities to determine charges to customers. The units utilized for calculating unit demand rates on Schedule 21 are maximum day kilometres for fixed transmission costs, and maximum day volume for Dawn fixed compression costs. The volume/distance basis for allocation of fixed costs recognizes the distance of haul. For Consumers' and TransCanada this is the system distance of 228 kilometres. For Union the volume to each take-off point on the line is the factor.

Transmission commodity costs are determined in accordance with the YCRR formula in the Rate 12 rate schedule. This formula, Yearly Commodity Revenue Requirement, provides a rate which tracks the cost of gas to Union and is adjusted at the end of each contract year to reflect actual costs. Pricing of service for the Dawn/Trafalgar system becomes quite involved. Separate rates are required for the usual easterly flow of gas as well as for occasional westerly flow from Trafalgar which sometimes occurs in the summer period. Also, some volumes received from Consumers' for transportation do not require compression at Dawn, although most volumes tendered at this point require this service. Separate rates are established for each service.

EBRO 405-2
Exhibit G1
Schedule 1
Revised

UNION GAS LIMITED

Summary of Utility Rate Base

Fiscal year ending March 31, 1987

Line No.	Particulars	($000's)
	Gas Utility Plant	
1	Gross plant at cost	$1,110,896
2	Less accumulated depreciation	250,591
3	Net utility plant	860,305
	Working Capital and Other Components	
4	Gas in storage and line pack gas	137,297
5	Inventory of stores spare equipment and merchandise and materials for resale	15,366
6	Merchandise and mortgages receivable	19,665
7	Cash working capital	16,272
8	Prepaid and deferred expenses	747
9	Total working capital components	189,347
10	Total rate base before deduction of accumulated deferred income taxes	1,049,652
11	Accumulated deferred income taxes	154,556
12	Total rate base	$ 895,096

November 20, 1985

Revised

UNION GAS LIMITED

Determination of Average Balance of Property Plant and Equipment

Fiscal year ending March 31, 1987

Line No.	Particulars ($000's)	O.E.B. Number	Utility Property Plant and Equipment Balance As at March 31 1986	1987	Average
			(a)	(b)	(c)
	Gas Plant in Service:				
	Intangible plant:				
1	Franchises and consents	401	$ 202	202	202
2	Other intangible plant	402	14	14	14
3			216	216	216
	Natural gas production plant:				
4	Gas leaseholds	404	276	276	276
5	Producing gas wells	406/7	1,706	1,707	1,707
6	Gas well structures	408	12	12	12
7	Other equipment	409	79	79	79
8			2,073	2,074	2,074
	Natural gas gathering plant:				
9	Land	410	4	4	4
10	Land rights	411	42	42	42
11	Structures and improvements	412/3/4	1,229	1,230	1,230
12	Gathering lines	415	2,869	3,270	3,069
13	Compressor equipment	416	465	465	465
14	Measuring and regulating equipment	417	549	549	549
15	Purification equipment	418	976	976	976
16			6,134	6,536	6,335
	Underground storage plant:				
17	Land	450	973	1,173	1,073
18	Land rights	451	6,153	6,153	6,153
19	Structures and improvements	452	8,357	9,706	9,031
20	Wells	453/4	12,066	13,656	12,861
21	Field lines	455	5,833	6,112	5,973
22	Compressor equipment	456	46,217	47,924	47,070
23	Measuring and regulating equipment	457	8,076	8,177	8,127
24	Base pressure gas	458	18,930	18,930	18,930
25	Other equipment	459	2	2	2
26			106,607	111,833	109,220

Revised

UNION GAS LIMITED

Determination of Average Balance of Property Plant and Equipment

Fiscal year ending March 31, 1987

Line No.	Particulars ($000's)	O.E.B. Number	Utility Property Plant and Equipment Balance As at March 31 1986	1987	Average
			(a)	(b)	(c)
	Gas Plant in Service (cont'd)				
	Transmission plant:				
1	Land	460	$ 1,480	1,480	1,480
2	Land rights	461	7,078	7,078	7,078
3	Structures and improvements	462/3/4	5,094	5,094	5,094
4	Mains	465	217,421	229,189	223,305
5	Compressor equipment	466	15,442	19,074	17,258
6	Measuring and regulating equipment	467	27,842	34,506	31,174
7			274,357	296,421	285,389
	Distribution plant:				
8	Land	470	1,599	1,599	1,599
9	Land rights	471	1,644	1,644	1,644
10	Structures and improvements	472	24,751	26,458	25,604
11	Services	473	160,441	173,540	166,991
12	House regulators and meter installations	474	46,204	49,438	47,821
13	Mains	475	275,908	286,534	281,221
14	Measuring and regulating equipment	477	6,010	6,032	6,021
15	Meters	478	46,566	48,628	47,597
16	Other distribution equipment	479	33	33	33
17			563,156	593,906	578,531
	General plant:				
18	Land	480	157	157	157
19	Structures and improvements	482	14,290	14,329	14,310
20	Office furniture and equipment	483	37,513	41,971	39,742
21	Transportation equipment	484	10,336	11,022	10,679
22	Heavy work equipment	485	3,042	3,146	3,094
23	Tools and work equipment	486	8,391	9,137	8,764
24	Equipment on customers' premises	487	75,604	84,596	80,099
25	Communication structures and equipment	488	3,614	3,629	3,622
26	Other general equipment	489	30	30	30
27			152,977	168,017	160,497

Revised

UNION GAS LIMITED

Determination of Average Balance of Property Plant and Equipment

Fiscal year ending March 31, 1987

Line No.	Particulars ($000's)	O.E.B. Number	Utility Property Plant and Equipment Balance As at March 31 1986	1987	Average
			(a)	(b)	(c)
	Gas Plant in Service (cont'd)				
	Undistributed plant:				
1	Unclassified plant - Contributions in aid of construction	496	$ (31,361)	(31,992)	(31,677)
2	Total gas plant in service	100	1,074,159	1,147,011	1,110,585
3	Gas plant held for future use - Ontario exploratory and development	102	246	375	311
4	Total property plant and equipment		$1,074,405	1,147,386	1,110,896

UNION GAS LIMITED

Determination of Average Balance of Accumulated Depreciation

Fiscal year ending March 31, 1987

Revised

Line No.	Particulars ($000's)	Utility Accumulated Depreciation Balance As at March 31 1986	1987	Average
		(a)	(b)	(c)
	Intangible plant:			
1	Intangible plant - other	111	116	114
	Natural gas production and gathering plant:			
2	Land rights	63	69	66
3	Structures and improvements	175	145	160
4	Wells and lines	1,335	1,389	1,362
5	Compressor equipment	173	185	179
6	Measuring and regulating equipment	120	138	129
7	Purification equipment	267	335	301
8		2,133	2,261	2,197
	Underground storage plant:			
9	Land rights	1,422	1,545	1,484
10	Structures and improvements	1,414	1,652	1,532
11	Wells and lines	4,084	4,649	4,367
12	Compressor equipment	8,255	9,667	8,961
13	Measuring and regulating equipment	1,928	2,102	2,015
14		17,103	19,615	18,359
	Transmission plant:			
15	Land rights	1,693	1,822	1,757
16	Structures and improvements	1,236	1,370	1,303
17	Mains	43,136	46,242	44,689
18	Compressor equipment	4,976	4,978	4,977
19	Measuring and regulating equipment	4,444	4,648	4,546
20		55,485	59,060	57,272

Revised

UNION GAS LIMITED

Determination of Average Balance of Accumulated Depreciation

Fiscal year ending March 31, 1987

Line No.	Particulars ($000's)	Utility Accumulated Depreciation Balance As at March 31 1986	1987	Average
		(a)	(b)	(c)
	Distribution plant:			
1	Land rights	$ 321	351	336
2	Structures and improvements	2,954	3,311	3,133
3	Services	37,462	43,631	40,547
4	Regulators	3,319	3,661	3,490
5	Regulator and meter installations	5,747	6,694	6,221
6	Mains	52,256	57,323	54,789
7	Measuring and regulating equipment	1,606	1,953	1,780
8	Meters	5,950	6,666	6,307
9		109,615	123,590	116,603
	General plant:			
10	Structures and improvements	1,966	2,252	2,109
11	Office furniture and equipment	1,867	2,168	2,017
12	Office equipment - computers	2,138	5,643	3,891
13	Transportation equipment	5,296	4,932	5,114
14	Transportation equipment - aircraft	563	626	594
15	Heavy work equipment	887	1,103	995
16	Tools and other equipment	2,206	2,632	2,419
17	Rental water heating equipment	34,649	39,194	36,922
18	Rental heating equipment	3,336	3,490	3,413
19	Rental make-up air equipment	181	195	188
20	NGV fueling equipment	40	167	104
21	Communication structures and equipment	1,077	1,227	1,152
22		54,206	63,629	58,918
23	Contributions in aid of construction	(2,580)	(3,163)	(2,872)
24	Accumulated depreciation - gas plant	$ 236,073	265,108	250,591

November 20, 1985

EBRO 405-2
Exhibit K3
Schedule 2
Page 1 of 3

Revised

UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Allocation of Income and Capital Taxes and Return
To Rate Base Components

Line No.	Particulars ($000's)	Total Rate Base Before Deduction of Accumulated Deferred Income Taxes (1) Total	Contributing To Deferred Taxes	(2) Other	Accumulated Deferred Income Taxes (3)	Total Rate Base (col (a) minus col. (d))	Taxes and Return at Composite Rate of (4) 19.9519%
		(a)	(b)	(c)	(d)	(e)	(f)
	Gas Utility Plant						
1	Intangible plant	$ 102	102		18	84	17
2	Natural gas production and gathering plant	6,212	6,208	4	1,099	5,113	1,020
3	Underground storage plant	89,665	88,592	1,073	18,994	70,671	14,102
4	Transmission plant	229,313	227,833	1,480	40,156	189,157	37,741
5	Distribution plant	461,928	460,329	1,599	81,394	380,534	75,925
6	General plant	101,579	101,422	157	17,933	83,646	16,689
7	Contributions in aid of construction	(28,805)	(28,805)		(5,093)	(23,712)	(4,731)
8	Exploration and development costs	311	311		55	256	51
9		860,305	855,992	4,313	154,556	705,749	140,814
	Working Capital and Other Components						
10	Gas in current underground storage and line pack gas	137,297		137,297		137,297	27,392
11	Inventory of stores, spare equipment, merchandise and material for resale	15,366		15,366		15,366	3,066
12	Merchandise accounts receivable	18,847		18,847		18,847	3,760
13	Mortgages receivable	818		818		818	163
14	Cash working capital	16,272		16,272		16,272	3,245
15	Prepaid and deferred expenses	747		747		747	149
16		189,347		189,347		189,347	37,775
17		$ 1,049,652	855,992	193,660	154,556	895,096	178,589

Notes

(1) Source - Exhibit K3, Schedule 2 - Page 2, Column (g).
(2) Amounts included in rate base under Column (c) 'Other' include items not deductible for income tax purposes such as land and working capital components.
(3) Allocated to gas utility plant based on net plant relationship under Column (b).
(4) 19.9519% determined on Page 3 and is applied to the total rate base as shown in column (e).

December 5, 1985

UNION GAS LIMITED

EBRO 405-2
Exhibit K3
Schedule 1
Revised

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Functionalization of Investment Carrying Costs

No.	Particulars ($000's)	Investment Carrying Costs: Property Taxes (Exh.F8) (Sch. 1) (Note 1)	Depreciation (Exhibit F7) (Schedule 1)	Income and Capital Taxes and Return (Exh K3 Sch2)	Total	Transfer of Indirect Costs (Exh K3 Sch 3): Indirect Costs	Allocation	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Gas Utility Plant							
1	Intangible plant	$	5	17	22	(22)		
2	Natural gas production and gathering plant	177	278	1,020	1,475		1,503	2,978
3	Underground storage plant	586	2,474	14,102	17,162		28,263	45,425
4	Transmission plant	5,030	6,488	37,741	49,259		4,111	53,370
5	Distribution plant	8,073	16,711	75,925	100,709		28,002	128,711
6	General plant	419	12,171	16,689	29,279	(29,279)		
7	Contributions in aid of construction		(583)	(4,731)	(5,314)	5,314		
8	Exploration and development costs		66	51	117	(117)		
9		14,285	37,610	140,814	192,709	(24,104)	61,879	230,484
	Working Capital and Other Components							
10	Gas in current underground storage and line pack gas			27,392	27,392	(27,392)		
11	Inventory of stores, spare equipment, merchandise and material for resale			3,066	3,066	(3,066)		
12	Merchandise accounts receivable			3,760	3,760	(3,760)		
13	Mortgages receivable			163	163	(163)		
14	Cash working capital			3,245	3,245	(3,245)		
15	Prepaid and deferred expenses			149	149	(149)		
16				37,775	37,775	(37,775)		
17		$ 14,285	37,610	178,589	230,484	(61,879)	61,879	230,484

Note 1 - Directly assigned.

December 5, 1985

EBRO 405-2
Exhibit F6
Tab 1
Schedule 1

Revised

UNION GAS LIMITED

Operating and Maintenance Expenses

Fiscal year ending March 31, 1987

Line No.	Particulars ($000's)	Total per Exhibit E1 Schedule 3	Adjustments (Note 2)	Adjusted Total
		(a)	(b)	(c)
	Operating Expense			
1	Underground storage	$ 6,735		6,735
2	Transmission	4,691		4,691
3	Distribution	26,776		26,776
4	General operation and engineering(1)	11,385		11,385
5	Distribution sales promotion	9,808		9,808
6	Distribution customer accounting	17,584		17,584
7	Administrative and general (1)	36,303	(1,971)	34,332
8	Total operating expense	113,282	(1,971)	111,311
	Maintenance Expense			
9	Underground storage	1,289		1,289
10	Transmission	2,475		2,475
11	Distribution	9,083		9,083
12	General	13		13
13	Total maintenance expense	12,860		12,860
14	Total Operating and Maintenance Expense	$ 126,142	(1,971)	124,171

Note:

(1) Net of amounts capitalized as follows:

15	General operations and engineering	$ (4,525)		(4,525)
16	Administrative and general	(4,453)		(4,453)
17		$ (8,978)		(8,978)

(2) Adjustments:

18	Wages salaries and other expenses assigned to non-utility activities	$ (1,715)
19	Charitable donations	(256)
20	Total	$ (1,971)

November 20, 1985

EBRO 405-2
Exhibit K3
Schedule 4
Revised

UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Functionalization of Cost of Gas and
Operating and Maintenance Expenses

Line No.	Particulars ($000's)	Total as Requested By Union	Phase I Adjustments	Total After Adjustments	Transfer of Indirect Costs (Exh.K3 Sch.5) Indirect Costs	Allocation	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Cost of gas	$1,095,910		1,095,910		5,327	1,101,237
	Operating and Maintenance Expense						
2	Underground storage	8,024		8,024		2,674	10,698
3	Transmission	7,166		7,166		4,979	12,145
4	Distribution	35,859		35,859		23,128	58,987
5	General operating and engineering	11,398		11,398	(11,398)		
6	Distribution sales promotion	9,808		9,808		3,838	13,646
7	Distribution customer accounting	17,584		17,584		5,784	23,368
8	Administrative and general	34,332		34,332	(34,332)		
9	Total	124,171		124,171	(45,730)	40,403	118,844
10	Total cost of gas and operating and maintenance expense	$1,220,081		1,220,081	(45,730)	45,730	1,220,081

December 5, 1985

EBRO 405-2
Exhibit K4
Schedule 1
Revised

UNION GAS LIMITED

Cost Allocation Study
March 31, 1987

Classification of Total Cost of Service
into Cost Categories

Line No.	Particulars ($000's)	Total	Cost Categories						
			Commodity Related	Capacity Related					
				Storage					
			Cost of Gas	Space	Deliver-ability	Trans-mission	Distri-bution	Customer Related	Direct Assignment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Investment Carrying Costs								
1	Production	$ 2,978	2,978						
2	Storage (Exh K6 Sch. 5 Page 1)	45,425		27,799	12,943	4,683			
3	Transmission (Exh K6 Sch. 5 Page 1)	53,370				53,370			
4	Distribution (Exh K4 Sch. 3)	128,711					32,448	96,263	
5		230,484	2,978	27,799	12,943	58,053	32,448	96,263	
6	Cost of Gas	1,101,237	1,101,237						
	Operating and maintenance expense								
7	Storage (Exh K6 Sch. 5 Page 1)	10,698	3,482	1,794	3,038	2,384			
8	Transmission (Exh K6 Sch. 5 Page 1)	12,145	1,236			10,909			
9	Distribution (Exh K4 Sch. 3)	58,987					11,046	47,941	
10	Distribution sales promotion	13,646	1,655					5,026	6,965
11	Distribution customer accounting	23,368						23,368	
12		118,844	6,373	1,794	3,038	13,293	11,046	76,335	6,965
13	Total cost of service	1,450,565	1,110,588	29,593	15,981	71,346	43,494	172,598	6,965
	Less - costs applicable to other than gas sales (per Exh K4 Sch 2):								
14	Other revenue items	(29,011)	(1,016)		(5)	(3)		(27,987)	
15	Storage and transportation service	(53,533)	(9,588)	(3,000)	(5,305)	(35,640)			
16		(82,544)	(10,604)	(3,000)	(5,310)	(35,643)		(27,987)	
17	Sub-total	1,368,021	1,099,984	26,593	10,671	35,703	43,494	144,611	6,965
18	Transfer of costs from storage to transmission			(5,319)	(2,134)	7,453			
19	Costs applicable to gas sales	$1,368,021	1,099,984	21,274	8,537	43,156	43,494	144,611	6,965

December 5, 1985

EBRO 405-2
Exhibit K5
Schedule 1
Page 1 of 3

Revised

UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Allocation of Cost Categories to Sales Classifications

Line No.	Sales Classification ($000's)	Rate Schedule	Total	Cost Categories						
				Commodity Related	Capacity Related					
					Storage					
				Cost of Gas	Space	Deliver-ability	Trans-mission	Distri-bution	Customer Related	Direct Assignment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Firm Sales									
	General service:	M2								
1	Residential		$ 379,041	223,961	8,417	3,676	13,553	15,525	111,484	2,425
2	Non-contract comm. and ind.		352,696	273,762	8,511	3,684	14,676	17,699	30,943	3,421
3	Firm ind. and comm.	M4	80,290	75,158	355	139	1,983	2,036	410	209
4	Interruptible ind. and comm.	M5A	17,013	16,101			354	400	112	46
5	Seasonal ind. and comm.	M6A	321	257			2	22	10	30
	Special large volume ind. and comm.	M7								
6	Firm		220,998	210,835	879	350	5,442	2,946	297	249
7	Seasonal		1,100	930			6	138	2	24
8	Large wholesale service	M9	37,999	34,985	919	350	1,614		79	52
9	Small wholesale service	M10	208	171	8	4	13		12	
10	Total firm sales		1,089,666	836,160	19,089	8,203	37,643	38,766	143,349	6,456
	Non-Firm Sales									
11	Interruptible ind. and comm.	M5A	96,350	89,088	1,395	170	1,775	2,558	1,030	334
	Special large volume ind. and comm.	M7								
12	Interruptible		182,005	174,736	790	164	3,738	2,170	232	175
13	Total non-firm sales		278,355	263,824	2,185	334	5,513	4,728	1,262	509
15	Total (per Exh K4 Schedule 1 Line 19)		$ 1,368,021	1,099,984	21,274	8,537	43,156	43,494	144,611	6,965

Allocation factors summarized on pages 2 and 3 attached.

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Exhibit K5
Schedule 1
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UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Allocation of Cost Categories to
Sales Classifications

Line No.	Sales Classification	Rate Schedule	Cost Categories: Commodity Related — Cost of Gas (Exh K5 Sch 6&9) (10^3m^3)	Capacity Related — Storage (Exh K5 Sch 2) — Space (10^3m^3)	Storage — Deliver-ability (10^3m^3d)	Transmission (Exh K5 Sch 5) (10^3m^3d)	Distribution (Exh K5 Sch 3) (10^3m^3d)	Customer Related (Note 1) (%)
			(a)	(b)	(c)	(d)	(e)	(f)
	Firm Sales							
	General service:	M2						
1	Residential service		1,497,558	462,351	7,346.77	11,293.41	11,449.67	77.092
2	Non-contract commercial and industrial		1,830,563	467,555	7,360.43	12,227.96	13,052.67	21.398
3	Firm industrial and commercial	M4	502,560	19,525	277.12	1,652.24	1,501.52	.284
4	Interruptible industrial and commercial	M5A	107,663			294.99	295.00	.077
5	Seasonal industrial and commercial	M6A	1,719			1.38	16.10	.007
	Special large volume industrial and commercial	M7						
6	Firm		1,409,787	48,283	698.90	4,534.18	2,172.33	.205
7	Seasonal		6,218			5.38	101.90	.001
8	Large wholesale service	M9	233,935	50,459	698.42	1,344.75		.055
9	Small wholesale service	M10	1,143	452	7.54	10.46		.008
10	Total firm sales		5,591,146	1,048,625	16,389.18	31,364.75	28,589.19	99.127

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Exhibit K5
Schedule 1
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UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

Allocation of Cost Categories to
Sales Classifications

Line No.	Sales Classification	Rate Schedule	Cost Categories					
			Commodity Related	Capacity Related				
				Storage (Exh K5 Sch 2)				
			Cost of Gas (Exh K5 Sch 6&9) (10**3m**3)	Space (10**3m**3)	Deliver-ability (10**3m**3d)	Transmission (Exh K5 Sch 5) (10**3m**3d)	Distribution (Exh K5 Sch 3) (10**3m**3d)	Customer Related (Note 1) (%)
			(a)	(b)	(c)	(d)	(e)	(f)
1	Firm Sales (balance forward)		5,591,146	1,048,625	16,389.18	31,364.75	28,589.19	99.127
	Non-Firm Sales							
2	Interruptible industrial and commercial	M5A	595,704	76,628	339.26	1,478.88	1,886.50	.713
3	Special large volume industrial and commercial interruptible	M7	1,168,410	43,391	328.21	3,114.38	1,600.33	.160
4	Total non-firm sales		1,764,114	120,019	667.47	4,593.26	3,486.83	.873
5	Total all sales		7,355,260	1,168,644	17,056.65	35,958.01	32,076.02	100.000
6	Allocation factors-as a rate-(2)		$/10**3m**3 149.551	$/10**3m**3 18.204	$/10**3m**3d 500.509	$/10**3m**3d 1,200.178	$/10**3m**3d 1,355.966	

Notes: (1) Determined on Exhibit K5 Schedule 4.

(2) Allocation factors for columns (a) to (e) are determined by dividing the total cost to be allocated as shown on Schedule 3 Line 19 columns (b) to (f) by the total allocation units shown above on line 5 under columns (a) to (e).

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EBRO 405-2
Exhibit K2
Schedule 1
Revised

UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987
Comparison of Revenue and Allocated Cost
by Sales and Service Classifications

Line No.	Particulars ($000's)	Rate Schedule	Revenue (Exh. F2) (Sch. 3)	Allocated Cost (Sched. 4)	Revenue Excess or (Deficiency)
			(a)	(b)	(c)
	Gas Sales				
	General service:	M2			
1	Residential		$ 348,272	379,041	(30,769)
2	Non-contract commercial and industrial		341,835	352,696	(10,861)
3	Firm industrial and commercial contract service	M4	81,013	80,290	723
	Interruptible industrial and commercial contract service	M5A			
4	Firm		17,538	17,013	525
5	Interruptible		94,027	96,350	(2,323)
6	Seasonal industrial and commercial contract service	M6A	286	321	(35)
	Special large volume industrial and commercial contract service	M7			
7	Firm		223,309	220,998	2,311
8	Interruptible		177,375	182,005	(4,630)
9	Seasonal		989	1,100	(111)
10	Total Rate M7		401,673	404,103	(2,430)
11	Large wholesale service	M9	37,262	37,999	(737)
12	Small wholesale service	M10	219	208	11
13	Total gas sales		1,322,125	1,368,021	(45,896)
14	Transportation and storage service for others	M12 M13 M14	46,084	53,533	(7,449)
15	Other revenue items		29,011	29,011	
16	Total		$1,397,220	1,450,565	(53,345)

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EBRO 405-2
Exhibit K6
Schedule 1
Revised

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Reconciliation of Storage and Transmission Costs with
System Cost Allocation Study

Line No.	Particulars ($000's)	Storage			Transmission			
		Total	Dawn Station	Other	Total	Dawn-Trafalgar	Dawn Compression	Other
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Cost of Service:							
1	Operating and maintenance expense	$ 10,698	6,770	3,928	$ 12,145	5,279		6,866
2	Investment carrying costs	45,425	9,897	35,528	53,370	34,720		18,650
3	Total	56,123	16,667	39,456	65,515	39,999		25,516
	Transfers:							
	50% of Dawn station measuring and regulating to transmission							
4	- Operating and maintenance	(466)	(466)		466	466		
5	- Investment carrying costs	(524)	(524)		524	524		
	Transfer of Dawn station compression to transmission							
6	- Operating and maintenance @ 60%	(3,502)	(3,502)		3,502		3,502	
7	- Investment carrying costs @ 47%	(4,159)	(4,159)		4,159		4,159	
8	Total after transfers	$ 47,472	8,016	39,456	$ 74,166	40,989	7,661	25,516

Notes:

(1) Total storage costs per system wide cost allocation study Exhibit K2
-Schedule 2 line 2 and line 7
(2) Total transmission costs per system wide cost allocation study Exhibit K2
-Schedule 2 line 3 and line 8

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EBRO 405-2
Exhibit K6
Schedule 2
Revised

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Classification of Storage and Dawn-Trafalgar Transmission Costs

Line No.	Particulars ($000's)		Storage						Dawn-Trafalgar Transmission		
			Total	Space	Demand	Commodity	Dehydrator Commodity	Other Space(1)	Total	Demand	Commodity
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Storage costs other than Dawn Station										
	Investment carrying charges										
1	Base pressure gas		$ 2,372	2,372							
2	Gas in current underground storage		26,918		3,673			23,245			
3	Wells lines land rights and working capital components		4,364	2,182	2,182						
4	Dehydrator		1,874		1,874						
5	Operations and maintenance		3,928	1,794	1,794		340				
6	Dawn-Trafalgar transmission costs								$ 40,989	39,753	1,236
7	Sub-total		39,456	6,348	9,523		340	23,245	40,989	39,753	1,236
8	Less: Tecumseh allocation (2)		(825)		(825)				(399)	(399)	
9	Sub-total		38,631	6,348	8,698		340	23,245	40,590	39,354	1,236
	Provision for unaccounted for gas										
10	Volume handled-(10^6m^3)	2,052.2									
11	Estimated unaccounted for at 0.5%-(10^6m^3)	10.2610									
12	Cost at $141.938/10^3m^3		1,456			1,456					
13	Total cost excluding Dawn compression costs		40,087	6,348	8,698	1,456	340	23,245	40,590	39,354	1,236
14	Dawn compression costs		8,016		6,458	1,558			7,661	6,077	1,584
15	Total costs including Dawn compression		$ 48,103	6,348	15,156	3,014	340	23,245	$ 48,251	45,431	2,820
	Gas cost components included above										
16	calculated at $141.938/10^3m^3		$ 29,430		3,673	2,512		23,245			

Notes (1): Carrying costs of the inventory volumes related to the load balancing and March market requirements of Union's gas sales customers only.

(2): Allocation of dehydrator to Tecumseh volumes based on peak day demand - Line 8 Column (c).
Direct assignment of Tecumseh metering costs - Line 8 Column (h).

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Exhibit K6
Schedule 3
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Revised

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Calculation of Unit Costs for
Storage and Transportation Service

Line No.	Particulars	Storage Space (a)	Storage Demand (b)	Storage Commodity (c)	Transportation Demand (d)
	Storage and Transmission Costs - ($000's)				
1	Storage	$ 6,348	15,156	3,014	
	Transmission				
2	Excluding Dawn compression				39,354
3	Dawn compression				6,077
4	Including Dawn compression				45,431
	Allocation Units - (10^6m^3)				
	Storage				
5	Working storage capacity	2,661.3			
6	Maximum day		36.252		
7	Annual volume handled			2,052.2	
	Transmission				
	Excluding Dawn compression				
8	Maximum day km (10^6m^3 kilometers)				14,394.8
	Dawn compression				
9	Maximum day volume				43.598
	Unit Costs - ($/10^3m^3)				
	Storage				
10	Cost per 10^3m^3 per month - Others	.199			
	Add unit carrying cost of inventory for old contracts -				
11	(20% * 19.9519% * $141.938/10^3m^3)/12	.472			
12	Cost per 10^3m^3 per month - Consumers'	.671			
13	Cost per 10^3m^3 per month		34.839		
14	Cost per 10^3m^3			1.469	
	Transportation				
	Excluding Dawn compression				
15	Cost per 10^3m^3 day per month for 228.94 kilometres				$ 52.158
	Dawn compression				
16	Cost per 10^3m^3 day per month				11.616
	Including Dawn compression				
17	Cost per 10^3m^3 day per month for 228.94 kilometres				$ 63.774

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EBRO 405-2
Exhibit K6
Schedule 3
Page 2 of 2
Revised

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Allocation of Dehydrator to Tecumseh
Storage Volumes on Behalf of Consumers' Gas

Line No.	Particulars ($000's)	Storage Demand
1	Dehydrator (Exh. K6 Sch. 2)	$ 1,874
	Allocation Units - (10^6m^3)	
2	Maximum day - Union	36.252
3	Maximum day - Tecumseh	28.500
4	Total	64.752
	Unit Cost - ($/10^3m^3)	
5	Cost per 10^3m^3 per month	2.412
	Allocation to Tecumseh	
6	(Line 3 x Line 5 x 12)	$ 825

December 5, 1985

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Revenue from Existing and Proposed Rates Compared to
Cost for Storage and Transportation Service for Others

EBRO 405-2
Exhibit K6
Schedule 4
Page 1 of 4

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Line No.	Particulars	Billing Units		Revenue Based on Existing Rates per EBRO 397		Cost		Revenue Excess (Deficiency)	Revenue Based on EBRO 405 Proposed Rates		
		Unit	Volume	Rate ($/10**3m3)	Revenue ($000s)	Rate ($/10**3m3)	Cost ($000s)		Rate ($/10**3m3)	Revenue ($000s)	Excess Over Cost
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate M12										
	The Consumers' Gas Company										
	Storage service:										
1	Demand	10**3m**3/d/mo	5,850	$ 29.646	$ 2,081	34.839	2,446	(365)	34.839	2,446	
2	Space**	10**3m**3/mo	365,000	.458	2,006	.474	2,075	(69)	.474	2,075	
3	Commodity	10**3m**3	720,250	.864	622	.735	529	93	.735	529	
4	Dehydration commodity	10**3m**3	236,580			.062	15	(15)	.062	15	
	Transportation service:										
	Demand:										
	Without Dawn compression										
5	- Easterly flow -	10**3m**3/d/mo	25,500	38.684	11,837	52.158	15,960	(4,123)	52.158	15,960	
	With Dawn compression										
6	- Easterly flow -	10**3m**3/d/mo	13,500	47.199	7,646	63.774	10,331	(2,685)	63.774	10,331	
	Commodity:										
	Without Dawn compression										
7	- Easterly flow	10**3m**3	1,593,450	1.440*	1,740	1.092	1,740		1.092*	1,740	
	With Dawn compression										
8	- Easterly flow	10**3m**3	1,658,290	1.692*	2,421	1.460	2,421		1.460*	2,421	
9	- Westerly flow	10**3m**3	982,330	1.721*	1,610	1.639	1,610		1.639*	1,610	
10	Subtotal Consumers'				29,963		37,127	(7,164)		37,127	
	Tecumseh Dehydration:										
11	Demand	10**3m**3/d/mo	28,500		1,800	3.579	1,224	576	3.579	1,224	
12	Commodity	10**3m**3	1,189,200		45	.062	74	(29)	.062	74	
13	Subtotal Tecumseh				1,845		1,298	547		1,298	
14	Total				31,808		38,425	(6,617)		38,425	

Note:
* Subject to yearly adjustment by application of the YCRR formula under Rate M12

** Calculation supporting line 2:

	212,500	.458	1,168	.671	1,711	(543)	.671	1,711	
	152,500	.458	838	.199	364	474	.199	364	
	365,000	.458	2,006	.474	2,075	(69)	.474	2,075	

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UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Revenue from Existing and Proposed Rates Compared to
Cost for Storage and Transportation Service for Others

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Exhibit K6
Schedule 4
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Revised

Line No.	Particulars	Billing Units		Revenue Based on Existing Rates per EBRO 397		Cost		Revenue Excess (Deficiency)	Revenue Based on EBRO 405 Proposed Rates		
		Unit	Volume	Rate ($/10**3m3)	Revenue ($000s)	Rate ($/10**3m3)	Cost ($000s)		Rate ($/10**3m3)	Revenue ($000s)	Excess Over Cost
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate M12 (con't)										
	TransCanada PipeLines										
	Transportation service:										
	Demand										
1	- 7 months	10**3m**3/d/mo	8,300	$ 47.199	$ 2,742	63.774	3,705	(963)	63.774	3,705	
2	- 5 months	10**3m**3/d/mo	8,840	47.199	2,086	63.774	2,819	(733)	63.774	2,819	
	Commodity										
	With Dawn compression										
3	- Easterly flow -	10**3m**3	655,700	1.519*	936	1.427	936		1.427*	936	
4	Total				5,764		7,460	(1,696)		7,460	
	Gaz Metropolitain Inc.										
	Storage service:										
5	Demand	10**3m**3/d/mo	1,900	29.646	676	34.839	794	(118)	34.839	794	
6	Space	10**3m**3/mo	280,000	.458	1,539	.199	669	870	.199	669	
7	Commodity	10**3m**3	550,132	.864	475	.735	404	71	.735	404	
8	Injection overrun	10**3m**3	9,868	1.839	18	1.121	11	7	2.266	22	11
9	Dehydration commodity	10**3m**3	135,600			.062	8	(8)	.062	8	
	Transportation service:										
10	Demand	10**3m**3/d/mo	1,900	47.199	1,076	63.774	1,454	(378)	63.774	1,454	
	Commodity:										
	With Dawn compression										
11	- Easterly flow	10**3m**3	280,000	1.692*	409	1.460	409		1.460*	409	
12	- Westerly flow	10**3m**3	252,001	1.721*	413	1.639	413		1.639*	413	
13	Total				4,606		4,162	444		4,173	11

Note:
* Subject to yearly adjustment by application of the YCRR formula under Rate M12

December 5, 1985

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Revenue from Existing and Proposed Rates Compared to
Cost for Storage and Transportation Service for Others

EBRO 405-2
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Revised

Line No.	Particulars	Billing Units		Revenue Based on Existing Rates per EBRO 397		Cost		Revenue Excess	Revenue Based on EBRO 405 Proposed Rates		
		Unit	Volume	Rate ($/10^3m^3)	Revenue ($000s)	Rate ($/10^3m^3)	Cost ($000s)	(Deficiency)	Rate ($/10^3m^3)	Revenue ($000s)	Excess Over Cost
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate M12 (con't)										
	Northern & Central Gas										
	Storage service:										
1	Demand	$10^3m^3/d/mo$	1,000	$ 29.646	$ 356	34.839	418	(62)	34.839	418	
2	Space	$10^3m^3/mo$	100,000	.458	550	.199	239	311	.199	239	
3	Commodity	10^3m^3	200,000	.864	173	.735	147	26	.735	147	
4	Dehydration commodity	10^3m^3	70,000			.062	4	(4)	.062	4	
	Transportation service:										
5	Demand	$10^3m^3/d/mo$	1,000	47.199	566	63.774	765	(199)	63.774	765	
	Commodity										
	With Dawn compression										
6	- Easterly flow	10^3m^3	90,000	1.692*	131	1.460	131		1.460*	131	
7	- Westerly flow	10^3m^3	90,000	1.721*	148	1.639	148		1.639*	148	
8	Total				1,924		1,852	72		1,852	
	Kingston P.U.C.										
	Storage service:										
9	Demand	$10^3m^3/d/mo$	70	29.646	25	34.839	29	(4)	34.839	29	
10	Space	$10^3m^3/mo$	7,000	.458	38	.199	17	21	.199	17	
11	Commodity	10^3m^3	14,030	.864	12	.735	10	2	.735	10	
12	Dehydration commodity	10^3m^3	5,565			.062			.062		
	Transportation service:										
13	Demand	$10^3m^3/d/mo$	70	47.199	40	63.774	54	(14)	63.774	54	
	Commodity										
	With Dawn compression										
14	- Easterly flow	10^3m^3	7,030	1.692*	10	1.460	10		1.460*	10	
15	- Westerly flow	10^3m^3	7,000	1.721*	11	1.639	11		1.639*	11	
16	Total				136		131	5		131	
17	Total Rate M12				44,238		52,030	(7,792)		52,041	11

Note:
* Subject to yearly adjustment by application of the YCRR formula under Rate M12

December 5, 1985

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Revenue from Existing and Proposed Rates Compared to
Cost for Storage and Transportation Service for Others

EBRO 405-2
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Revised

Line No.	Particulars	Billing Units		Revenue Based on Existing Rates per EBRO 397		Cost		Revenue Excess (Deficiency)	Revenue Based on EBRO 405 Proposed Rates		
		Unit	Volume	Rate ($/10^3m^3)	Revenue ($000s)	Rate ($/10^3m^3)	Cost ($000s)		Rate ($/10^3m^3)	Revenue ($000s)	Excess Over Cost
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Total Rate M12 (fvd.)				$44,238		52,030	(7,792)		52,041	11
	Rate M13 - The Consumers' Gas Company										
2	Demand	monthly		14833.000	178	12750.000	153	25	12750.000	153	
3	Commodity	10^3m^3	199,394	1.594	318			318	1.627	324	324
4	Total Rate M13				496		153	343		477	324
	Short-Term Compression The Consumers' Gas Company										
5	Demand	season									
6	Commodity	10^3m^3									
7	Total										
	Rate M14 - Bickford Sombra Transportation Agreement										
8	Demand	monthly				66083.000	793	(793)	66083.000	793	
9	Commodity	10^3m^3	910,000	1.483	1,350	.612	557	793	.612	557	
10	Total				1,350		1,350			1,350	
11	Total Transportation and Storage				$46,084		53,533	(7,449)		$ 53,868	335

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UNION GAS LIMITED

Cost Allocation Study
Fiscal Year Ending March 31, 1987

EBRO 405-2
Exhibit K3
Schedule 1
Revised

Functionalization of Investment Carrying Costs

No.	Particulars ($000's)	Investment Carrying Costs: Property Taxes (Exh.F8) (Sch. 1) (Note 1)	Depreciation (Exhibit F7) (Schedule 1)	Income and Capital Taxes and Return (Exh K3 Sch2)	Total	Transfer of Indirect Costs (Exh K3 Sch 3): Indirect Costs	Allocation	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Gas Utility Plant							
1	Intangible plant	$	5	17	22	(22)		
2	Natural gas production and gathering plant	177	278	1,020	1,475		1,503	2,978
3	Underground storage plant	586	2,474	14,102	17,162		28,263	45,425
4	Transmission plant	5,030	6,488	37,741	49,259		4,111	53,370
5	Distribution plant	8,073	16,711	75,925	100,709		28,002	128,711
6	General plant	419	12,171	16,689	29,279	(29,279)		
7	Contributions in aid of construction		(583)	(4,731)	(5,314)	5,314		
8	Exploration and development costs		66	51	117	(117)		
9		14,285	37,610	140,814	192,709	(24,104)	61,879	230,484
	Working Capital and Other Components							
10	Gas in current underground storage and line pack gas			27,392	27,392	(27,392)		
11	Inventory of stores, spare equipment, merchandise and material for resale			3,066	3,066	(3,066)		
12	Merchandise accounts receivable			3,760	3,760	(3,760)		
13	Mortgages receivable			163	163	(163)		
14	Cash working capital			3,245	3,245	(3,245)		
15	Prepaid and deferred expenses			149	149	(149)		
16				37,775	37,775	(37,775)		
17		$ 14,285	37,610	178,589	230,484	(61,879)	61,879	230,484

Note 1 - Directly assigned.

December 5, 1985

SCHEDULE 25
PAGE 1

EBRO 405-2
Exhibit K3
Schedule 2
Page 1 of 3

Revised

UNION GAS LIMITED
Cost Allocation Study
Fiscal Year Ending March 31, 1987
Allocation of Income and Capital Taxes and Return
To Rate Base Components

Line No.	Particulars ($000's)	Total Rate Base Before Deduction of Accumulated Deferred Income Taxes (1) Total	Contributing To Deferred Taxes	(2) Other	Accumulated Deferred Income Taxes (3)	Total Rate Base (col (a) minus col. (d))	Taxes and Return at Composite Rate of (4) 19.9519%
		(a)	(b)	(c)	(d)	(e)	(f)
	Gas Utility Plant						
1	Intangible plant	$ 102	102		18	84	17
2	Natural gas production and gathering plant	6,212	6,208	4	1,099	5,113	1,020
3	Underground storage plant	89,665	88,592	1,073	18,994	70,671	14,102
4	Transmission plant	229,313	227,833	1,480	40,156	189,157	37,741
5	Distribution plant	461,928	460,329	1,599	81,394	380,534	75,925
6	General plant	101,579	101,422	157	17,933	83,646	16,689
7	Contributions in aid of construction	(28,805)	(28,805)		(5,093)	(23,712)	(4,731)
8	Exploration and development costs	311	311		55	256	51
9		860,305	855,992	4,313	154,556	705,749	140,814
	Working Capital and Other Components						
10	Gas in current underground storage and line pack gas	137,297		137,297		137,297	27,392
11	Inventory of stores, spare equipment, merchandise and material for resale	15,366		15,366		15,366	3,066
12	Merchandise accounts receivable	18,847		18,847		18,847	3,760
13	Mortgages receivable	818		818		818	163
14	Cash working capital	16,272		16,272		16,272	3,245
15	Prepaid and deferred expenses	747		747		747	149
16		189,347		189,347		189,347	37,775
17		$ 1,049,652	855,992	193,660	154,556	895,096	178,589

Notes

(1) Source - Exhibit K3, Schedule 2 - Page 2, Column (g).
(2) Amounts included in rate base under Column (c) 'Other' include items not deductible for income tax purposes such as land and working capital components.
(3) Allocated to gas utility plant based on net plant relationship under Column (b).
(4) 19.9519% determined on Page 3 and is applied to the total rate base as shown in column (e).

December 5, 1985

EBRO 405-2
Exhibit K6
Schedule 1
Revised

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Reconciliation of Storage and Transmission Costs with
System Cost Allocation Study

Line No.	Particulars ($000's)	Storage			Transmission			
		Total	Dawn Station	Other	Total	Dawn-Trafalgar	Dawn Compression	Other
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Cost of Service:							
1	Operating and maintenance expense	$ 10,698	6,770	3,928	$ 12,145	5,279		6,866
2	Investment carrying costs	45,425	9,897	35,528	53,370	34,720		18,650
3	Total	56,123	16,667	39,456	65,515	39,999		25,516
	Transfers:							
	50% of Dawn station measuring and regulating to transmission							
4	- Operating and maintenance	(466)	(466)	-	466	466		
5	- Investment carrying costs	(524)	(524)		524	524		
	Transfer of Dawn station compression to transmission							
6	- Operating and maintenance @ 60%	(3,502)	(3,502)		3,502		3,502	
7	- Investment carrying costs @ 47%	(4,159)	(4,159)		4,159		4,159	
8	Total after transfers	$ 47,472	8,016	39,456	$ 74,166	40,989	7,661	25,516

Notes:

(1) Total storage costs per system wide cost allocation study Exhibit K2
-Schedule 2 line 2 and line 7
(2) Total transmission costs per system wide cost allocation study Exhibit K2
-Schedule 2 line 3 and line 8

December 5, 1985

EBRO 405-2
Exhibit K6
Schedule 2
Revised

UNION GAS LIMITED

Storage and Transportation
Cost Allocation Study
Fiscal Year Ending March 31, 1987

Classification of Storage and Dawn-Trafalgar Transmission Costs

Line No.	Particulars ($000's)		Storage						Dawn-Trafalgar Transmission		
			Total	Space	Demand	Commodity	Dehydrator Commodity	Other Space(1)	Total	Demand	Commodity
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Storage costs other than Dawn Station										
	Investment carrying charges										
1	Base pressure gas		$ 2,372	2,372							
2	Gas in current underground storage		26,918		3,673			23,245			
	Wells lines land rights and										
3	working capital components		4,364	2,182	2,182						
4	Dehydrator		1,874		1,874						
5	Operations and maintenance		3,928	1,794	1,794		340				
6	Dawn-Trafalgar transmission costs								$ 40,989	39,753	1,236
7	Sub-total		39,456	6,348	9,523		340	23,245	40,989	39,753	1,236
8	Less: Tecumseh allocation (2)		(825)		(825)				(399)	(399)	
9	Sub-total		38,631	6,348	8,698		340	23,245	40,590	39,354	1,236
	Provision for unaccounted for gas										
10	Volume handled-(10*6m*3)	2,052.2									
11	Estimated unaccounted for at 0.5%-(10*6m*3)	10.2610									
12	Cost at $141.938/10*3m*3		1,456			1,456					
13	Total cost excluding Dawn compression costs		40,087	6,348	8,698	1,456	340	23,245	40,590	39,354	1,236
14	Dawn compression costs		8,016		6,458	1,558			7,661	6,077	1,584
15	Total costs including Dawn compression		$ 48,103	6,348	15,156	3,014	340	23,245	$ 48,251	45,431	2,820
16	Gas cost components included above calculated at $141.938/10*3m*3		$ 29,430		3,673	2,512		23,245			

Notes (1): Carrying costs of the inventory volumes related to the load balancing and March market requirements of Union's gas sales customers only.

(2): Allocation of dehydrator to Tecumseh volumes based on peak day demand - Line 8 Column (c).
Direct assignment of Tecumseh metering costs - Line 8 Column (h).

December 5, 1985

SCHEDULE 27

APPENDIX IV

STORAGE RATE SCHEDULES

H. ZINDER & Associates

Washington, D.C.
Dallas
New York
Salem, Oregon

Summary of

Rate Schedules of Natural Gas Pipeline Companies

As Filed with the
Federal Energy Regulatory Commission
and the National Energy Board of Canada

60TH EDITION

SEPTEMBER 15, 1985

©Zinder Companies, Inc., 1985

ALGONQUIN GAS TRANSMISSION COMPANY

STB, FIRM AND BACKUP STORAGE SERVICE

AVAILABILITY. To any buyer purchasing under a firm gas rate schedule executing a service agreement. This service is based on service rendered to Seller by Texas Eastern Transmission Corporation under Rate Schedule SS-II.

SERVICE. Firm up to (1) Buyer Firm Daily Portion of Buyers Storage Demand and (2) Buyer's Backup Portion of Buyer's Storage Demand. Seller is not obligated to deliver gas on any day for Buyer's Backup Portion of its Storage Demand to the extent that such delivery in conjunction with deliveries made by Seller to Buyer under Seller's F-1 and WS-1 on such day exceeds Buyer's Total Maximum Daily Quantity for service under Seller's F-1 and WS-1. Seller may make deliveries of Buyers Backup Portion of Storage Demand in excess of above quantities, but only to extent agreed upon by Seller in advance, on a day-to-day basis.

RATE.

Reimbursement of Payment

To Texas Eastern

Demand Charge	$ 0.81
Firm Daily Portion Demand Charge	$10.018
Storage Capacity Charge	2.80¢
Injection Charge	1.0¢
Withdrawal Charge	6.62¢

Handling Charge of Seller

Demand Handling Charge	$12.75
Commodity Handling Charge	14.74¢

FUEL REIMBURSEMENT. Buyer shall reimburse Seller for (1) reimbursement of fuel to Texas Eastern 2% (2) reimbursement of Seller's fuel 0.5%

MINIMUM BILL:

MONTHLY. Demand Charges and Capacity Charges paid Texas Eastern plus Seller's demand handling charge.

ANNUAL COMMODITY HANDLING CHARGE. 75% multiplied by Buyer's Storage Capacity reduced for Fuel Reimbursement.

ANNUAL TEXAS EASTERN SS-II BILLING ADJUSTMENT. Any additional charges or reduction in charges from Texas Eastern under SS-II shall be flowed through.

HEAT CONTNET. Not less than 960 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F.

EFFECTIVE DATE. August 1, 1985.

S-IS, STORAGE-INTERIM SERVICE

AVAILABILITY. To an F-1 Buyer for the purchase of storage service for the period from the date of authorization and terminating June 15, 1986.

SERVICE. Deliveries are subject to Texas Eastern providing sufficient quantities to permit such deliveries. Daily deliveries are limited to lessor of (a) or (b) as follows: (a) the difference between Buyer's total firm maximum daily quantity for service under Seller's F-1, WS-1 and STB, and the aggregate quantity of gas delivered to Buyer on such day under F-1, WS-1 and STB and (b) Buyer's Maximum Daily Withdrawal Quantity under S-IS reduced by fuel reimbursement required for such day. Seller may make deliveries in excess of above quantities to extent Seller agrees to do so on a day-to-day basis.

RATE

For Reimbursement of Payment to

Consolidated Gas Transmission Corporation for Inventory Sales Gas

Payment for Inventory Sales Gas	$3.7679

For Reimbursement of Payment to

Texas Eastern

Demand Charge	$0.81
Space Charge	2.8¢
Injection Charge	1.0¢
Withdrawal Charge	16.29¢

Handling Charge of Seller

Seller's Handling Charge	14.74¢

FUEL REIMBURSEMENT. Buyer shall reimburse Seller for any fuel required to render service as follows. For reimbursement of Texas Eastern's fuel 2%. For reimbursement of Seller's fuel 1%.

MINIMUM BILL. Sum of reimbursements of payments to Texas Eastern for the Demand Charge and the Space Charge.

HEAT CONTENT. Minimum 960 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F.

EFFECTIVE DATE. August 1, 1985.

ANR STORAGE COMPANY

X-1, X-2, X-5, STORAGE SERVICE

AVAILABILITY. United Gas Pipe Line Co. (X-1)
Panhandle Eastern Pipe Line Co. (X-2)
Northern Indiana Public Service Co. (X-5)

SERVICE. Off-peak. During each month of the Winter Period November 1 through March 31, ANR will deliver 20% of the Winter Contract Demand (Volume received for delivery the preceding summer). Daily deliveries are up to the Maximum Daily Quantity. The Annual Contract Volume is the maximum Volume to be stored during the Summer Period and is 100 times the Maximum Daily Quantity. ANR will advise prior to each month of daily volumes and days on which gas is to be delivered. Buyer may elect not to take redelivery on any day of the gas so scheduled by giving 24 hours notice and in that Winter Period ANR shall be relieved of further obligation to deliver in that Winter Period such volume not taken by Buyer. ANR may, with Buyer's concurrence, deliver such gas at a later date in the Winter Period.

RATE

Monthly Charge	$1,542.750 (X-1)
	5.143 (X-2)
	102.850 (X-5)

MINIMUM MONTHLY BILL. Monthly Charge.

HEAT CONTENT. Not less than 950 Btu nor more than 1050 Btu per cu. ft.

BTU ADJUSTMENT. Volumes delivered adjusted pro rata for heat content variation from 1,000 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F.

EFFECTIVE DATE. November 1, 1982.

X-3, X-6, X-9, X-11, STORAGE SERVICE

AVAILABILITY. Panhandle Eastern Pipe Line Co. (X-3)
United Cities Gas Company (X-6)
Southern Natural Gas Company (X-9)
Inter-City Gas Corp. (X-11)

SERVICE. Firm (50-day) to the following quantities.

Maximum Daily Quantity until 80% of Winter Contract Quantity Withdrawn.

80% of Maximum Daily Quantity until 90% of Winter Contract Quantity Withdrawn.

60% of Maximum Daily Quantity until 100% of Winter Contract Quantity Withdrawn.

The Annual Contract Volume is the Maximum Volume to be stored during the summer and is 50 times the Maximum Daily Quantity. The Winter Contract Volume is equal to volume received for storage during prior Summer Period from April 1 through October 31.

RATE

Monthly Charge	$245.778 (X-3)
	7.928 (X-6)
	466.337 (X-9)
	31.713 (X-11)

MINIMUM MONTHLY BILL. Monthly Charge.

HEAT CONTENT. Not less than 950 Btu nor more than 1050 Btu per cu. ft.

BTU ADJUSTMENT. Volumes delivered adjusted pro rata for heat content variation from 1000 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F.

EFFECTIVE DATE. November 1, 1982.

X-4, X-10, STORAGE SERVICE

AVAILABILITY. Mississippi River Transmission Corp. (X-4)
Southern Natural Gas Co. (X-10)

SERVICE. Firm (100-day) up to the following quantities:
- Maximum Daily Quantity until 80% of Winter Contract Quantity Withdrawn
- 80% of Maximum Daily Quantity until 90% of Winter Contract Quantity Withdrawn
- 60% of Maximum Daily Quantity until 100% of Winter Contract Quantity Withdrawn

The Annual Contract Volume is the maximum volume to be stored during the summer and is 100 times the Maximum Daily Quantity. The Winter Contract Volume is equal to volume received for storage during prior summer period from April 1 through October 31.

RATE.
Monthly Charge $175,375 (X-4)
328,583 (X-10)

MINIMUM MONTHLY BILL. Monthly Charge.
HEAT CONTENT. Not less than 950 Btu nor more than 1050 Btu per cu. ft.
BTU ADJUSTMENT. Volumes delivered adjusted pro rata for heat content variation from 1000 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. November 1, 1982.

COLUMBIA GAS TRANSMISSION CORPORATION

WS, WINTER SERVICE

AVAILABILITY. To CDS Buyers (excluding Zone 5) executing a Winter Service Agreement for a specified Winter Contract Quantity and Maximum Daily Quantity from November 1 through April 30. Winter Contract Quantity is not to be:
(1) Less than 60 nor more than 90 times Maximum Daily Quantity in Zones 1 and 3,
(2) Less than 50 nor more than 110 times Maximum Daily Quantity in Zone 2,
(3) Less than 50 nor more than 90 times Maximum Daily Quantity in Zones 4, 6, and 7.

SERVICE. Firm
RATE.

Zones 1-7 [1]	Non-Shielded Customers	Shielded Customers
Initial Period [2]	3.64¢	3.64¢
Monthly Demand [3]	2.109	$2.10
Contract Quantity [4]	4.82¢	4.77¢
Excess of MDQ [5]	43.73¢	43.73¢

[1] Rates expressed in Dekatherms
[2] Additional charge per Dth for gas from Seller's own supply.
[3] Charge per Dth of WS Maximum Daily Quantity.
[4] Charge per month per Dth of Winter Contract Quantity.
[5] Charge per Dth for scheduled deliveries from Buyer's Reserved Gas Balance in excess of Maximum Daily Quantity.

MINIMUM MONTHLY BILL. Demand Charge plus the Winter Contract Quantity Charge each month of the year.
BILLING DEMAND. Maximum Daily Quantity.
HEAT CONTENT. Minimum 967 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985.

CONSOLIDATED GAS TRANSMISSION CORPORATION*

GSS, GENERAL STORAGE SERVICE

AVAILABILITY. To any Buyer. Seller agrees to receive and redeliver stated storage quantities of gas in Allegany or Steuben Counties in New York, or Clinton, Potter or Tioga Counties in Pennsylvania.
SERVICE. Firm. Maximum daily storage withdrawal quantity limited to Buyer's Storage Demand and total withdrawal limited to Storage Capacity Volume (top storage) of Buyer. The Storage Capacity Volume not to be more than 110 or less than 50 times Buyer's Storage Demand.

RATE.
Storage Demand Charge: $0.8[illegible] per month per Dth of Storage Demand.
Storage Capacity Charge: 2.80¢ per month per Dth of Storage Capacity Volume.
Injection or Withdrawal Charge: 1.0¢ per Dth delivered to [illegible] withdrawn from storage.

MINIMUM BILL.
Monthly—Sum of Storage Demand Charge and Storage Capacity Volume Charge.
Minimum Annual Volume Injected and Withdrawn Charges—Payment for a minimum injection volume equal to 65% of Buyer's Storage Capacity Volume at 1.0¢ per Dth and payment for an equal minimum withdrawal volume.

EXCESS DELIVERY CHARGE.
FROM BUYER'S BALANCE 47.85¢
NOT FROM BUYER'S BALANCE
NON-GAS 30.08¢
GAS 342.54¢
TOTAL 372.63¢

DEMAND CHARGE ADJUSTMENT. Storage Demand Charge reduced by the percentage ratio between Buyer's Storage Demand and Storage Capacity Volume times $9.72 per Dth of the delivery deficiency below Buyer's daily delivery entitlement.
STORAGE YEAR. Twelve-month period beginning with the day specified in the service agreement.
HEAT CONTENT. Not less than 967 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985.

EASTERN SHORE NATURAL GAS COMPANY

GSS-1, GENERAL STORAGE SERVICE

AVAILABILITY. To CD Buyers executing a service agreement.
SERVICE. Firm
RATE.
Demand Charge: $5.1291 per month of Dth of Storage Demand.
Storage Capacity Volume Charge: $0.017 per month per Dth of Storage Capacity Volume.
Volume Injected or Withdrawn Charge: $0.01 per Dth delivered into or withdrawn from storage.

MINIMUM BILL.
Monthly—Sum of the Demand Charge and the Storage Capacity Volume Charge.
Minimum Annual Volume Injected or Withdrawn Charges—During each storage year, payment for a minimum injection volume equal to 65% of Buyer's Storage Capacity Volume at $0.01 per Dth and payment for a minimum withdrawal volume of the same amount.

EXCESS DELIVERY CHARGE: $1.3976 per Dth for gas from Buyer's Balance $5.2210 per Dth for gas not from Buyer's Balance.
STORAGE ACCOUNT CREDIT. Charge of $3.8134 per Dth for gas transferred, at Seller's option, from Seller's injected volumes to Buyer's Storage Gas Account.
STORAGE YEAR. Twelve months ending March 31.
HEAT CONTENT. Not less than 980 nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. May 1, 1985.

LGA-1, LIQUEFIED NATURAL GAS STORAGE SERVICE

AVAILABILITY. To any utility or gas distribution agency purchasing from Seller under other rate schedules.
SERVICE. Firm, storage service consisting of liquefaction of natural gas, the storage of such liquefied gas and the gasification and delivery of such gas during withdrawal period of November 1 through March 31.
Seller to deliver volumes at Buyer's election up to the specified Liquefaction Demand (maximum volume Seller is obligated to deliver on any day) and Buyer's Liquefaction Capacity Volume (volume Seller is obligated to Liquefy, store and keep available during any single Withdrawal Period).

***COMPANY HAS FILED NEW MAJOR RATES SHOWN IN "SUSPENDED SECTION."**

RATE:
Demand Charge: $2.7351 per month per Dth of Liquefaction Demand.
Capacity Charge: $0.283 per month per Dth of Liquefaction Capacity Volume.
Delivery Charge: $0.215 per Dth delivered from storage.
MINIMUM NONTHLY BILL: Sum of the Demand Charge and the Capacity Charge.
EXCESS DELIVERY CHARGE: $8.8624 per Dth for gas from Buyer's Balance $12.6758 per Dth for gas not from Buyer's Balance.
HEAT CONTENT: Not less than 980 nor more than 1100 Btu per cu. ft.
MEASURMENT BASE: 14.73 psia, 60°F.
EFFECTIVE DATE: May 1, 1985

WSS, WASHINGTON STORAGE SERVICE

AVAILABILITY: To any utility or gas distribution agency purchasing from Seller under CD or G rate schedules; and when Buyer and Seller execute a service agreement for WSS under this rate schedule.
SERVICE: Firm, not to exceed Buyer's storage gas balance. Buyer to nominate storage injection volumes in the ratios of .9767 Mcf of base gas to one (1) Mcf top storage gas or one (1) Mcf of base gas to one (1) Mcf top storage gas.
RATE:
(a) Storage Capacity Quantity Charge—7.91¢ per month per Dth of Storage Capacity Quantity
(b) Quantity Withdrawal Charge—3.9¢ per month per Dth for gas withdrawn from storage.
Excess Delivery Charge
$.9882 per Dth from Buyer's Storage Gas Balance
$4.8016 not reducing Buyer's Storage Gas Balance.
MINIMUM MONTHLY BILL: Storage Capacity Quantity Charge
HEAT CONTENT: Not less than 980 nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE: 14.73 psia 60°F
EFFECTIVE DATE: May 1, 1985

MIDWESTERN GAS TRANSMISSION COMPANY

SS-1, STORAGE SERVICE (SOUTHERN SYSTEM)

AVAILABILITY: Southern System; to Contract Demand Service Buyers contracting for a Daily Storage Quantity
SERVICE: Firm; up to Daily Storage Quantity and Winter Storage Quantity. Winter Storage Quantity is 75 times the Daily Storage Quantity. Withdrawal Period is November 1 through April 30.
RATE:
Monthly Demand Charge—$14.13 per Mcf of Daily Storage Quantity.
Commodity Charge—4.53¢ per Mcf
Gas Charge—265.53¢ per Dth
MINIMUM MONTHLY BILL: Demand Charge
EXCESS WITHDRAWAL CHARGE: $5.2153 per Mcf (includes Gas Charge) of gas requested by Buyer and delivered by Seller, at its option in excess of Seller's obligation.
RETURN GAS CHARGE: Additional charge of 25.87¢ per Mcf of gas Seller elects to inject for Buyer's account up to Winter Storage Quantity to make up for volumes not made available by Buyer.
HEAT CONTENT: Not less than 967 Btu per cu. ft.
MEASUREMENT BASE: 14.73 psia, 60°F
EFFECTIVE DATE: August 15, 1985

NATURAL GAS PIPELINE COMPANY OF AMERICA*

S-1, STORAGE SERVICE

AVAILABILITY: To DMQ-1 Buyers executing a service agreement.
SERVICE: Firm
RATE:

Demand Charge:	$.94	per Mcf of Daily Withdrawal Quantity
Capacity Charge:	1.52¢	per Mcf of Storage Capacity
Injection Charge:	5.07¢	per Mcf for injection from June 1 to end of February
Withdrawal Charge:	5.07¢	per Mcf in any month of Withdrawal

MINIMUM MONTHLY BILL: Sum of Demand Charge and Storage Capacity Charge
DAILY WITHDRAWAL QUANTITY: Maximum daily contract volume which may be withdrawn for customer.
The total of any customer's withdrawals of gas during the Withdrawal Period of November 1 of any year to the next succeeding April 30 shall not exceed 66-⅔% of the Storage Gas Balance as of November 1.
During the injection period, May 1 through October 31, Natural not obligated to inject as top storage gas for account of any Buyer a volume which would bring amount of top storage for such Buyer in excess of the contracted Storage Capacity which is 45 times Buyer's Daily Withdrawal Quantity.
EXCESS-DEFICIENCY CHARGE: Demand Charge reduced by 37.60¢ per Mcf of the delivery deficiency below quantity Buyer is entitled to receive on that day. 37.60¢ per Mcf for deliveries in excess of Buyer's Daily Withdrawal Quantity at Seller's option if gas is available from Buyer's Storage Gas Balance.
BTU ADJUSTMENT: Metered volume adjusted pro rata each day for actual heat content variation from 1000 Btu per cu. ft.
HEAT CONTENT: Not less than 950 Btu per cu. ft.
MEASUREMENT BASE: 14.65 psia, 60°F
EFFECTIVE DATE: February 1, 1985

MS-1, STORAGE SERVICE

AVAILABILITY: To DMQ-1 or G-1 Buyers executing a service agreement.
SERVICE: Firm, during Withdrawal Period beginning November 1 and ending next February 28. Buyer to make available a maximum quantity of gas equal to 100 times Buyer's Daily Withdrawal Quantity (except 50 times Buyer's DWQ is to be received for the Injection Period prior to October 31, 1976 for base gas) for injection into top storage during the March 1 to October 31 Injection Period.
RATE: Monthly Demand Charge—$9.43 per Mcf of Daily Withdrawal Quantity.
MINIMUM MONTHLY BILL: Demand Charge
DAILY WITHDRAWAL QUANTITY: Maximum volume Seller is obligated to deliver on any day during the Withdrawal Period.
WINTER WITHDRAWAL QUANTITY: Maximum volume of top storage gas Seller is obligated to deliver during the Withdrawal Period and equivalent to 100 times the Daily Withdrawal Quantity.
AUTHORIZED OVERRUN CHARGE: 113.00¢ per Mcf for gas delivered at Seller's option in excess of Daily Withdrawal Quantity.
DELIVERY DEFICIENCY CHARGE: 113.00¢ per Mcf credit for delivery deficiency below the lesser of Buyer's Daily Withdrawal Quantity or the quantity Buyer was entitled to receive on that day.
BTU ADJUSTMENT: Metered volume adjusted pro rata each day for actual heat content variation from 1000 Btu per cu. ft.
HEAT CONTENT: Minimum 950 Btu per cu. ft.
MEASUREMENT BASE: 14.65 psia, 60°F
EFFECTIVE DATE: February 1, 1985

MS-2, STORAGE SERVICE

AVAILABILITY: To DMQ-1 or G-1 Buyers executing a service agreement.
SERVICE: Firm, during Withdrawal Period beginning November 21 and ending next February 28. Buyer to make available a maximum quantity of gas equal to 100 times Buyer's Daily Withdrawal Quantity for injection into top storage during the March 1 to October 31 Injection Period.
RATE: Monthly Demand Charge—$7.42 per Mcf of Daily Withdrawal Quantity.
MINIMUM MONTHLY BILL: Demand Charge
DAILY WITHDRAWAL QUANTITY: Maximum volume Seller is obligated to deliver on any day during the Withdrawal Period.
WINTER WITHDRAWAL QUANTITY: Maximum volume of top storage gas Seller is obligated to deliver during the Withdrawal Period and equivalent to 100 times the Daily Withdrawal Quantity.
EXCESS DELIVERY CHARGE: 89.00¢ per Mcf for gas delivered at Seller's option in excess of Daily Withdrawal Quantity. $4.02 per Mcf for gas delivered at Seller's option in excess of Daily Withdrawal and Winter Withdrawal Quantity and for optional deliveries to make up for Buyer's injection deficiencies.

"COMPANY HAS FILED NEW MAJOR RATES SHOWN IN "SUSPENDED SECTION."

DELIVERY DEFICIENCY CHARGE. 89.00¢ per Mcf credit for delivery deficiency below the lesser of Buyer's Daily Withdrawal Quantity or the quantity Buyer was entitled to receive on that day.
BTU ADJUSTMENT. Metered volume adjusted pro rata each day for actual heat content variation from 1000 Btu per cu. ft.
HEAT CONTENT. Minimum 950 Btu per cu. ft.
MEASUREMENT BASE. 14.65 psia, 60°F.
EFFECTIVE DATE. February 1, 1985

MS-3, STORAGE SERVICE

AVAILABILITY. To DMQ-1 or G-1 Buyers executing a service agreement.
SERVICE. Firm, during Withdrawal Period beginning November 1 and ending next March 31. Buyer to make available a maximum quantity of gas equal to the Winter Withdrawal Quantity for injection into top storage dunng the April to October 31 Injection Period.
RATE. Monthly Demand Charge—69.39¢ per Mcf times one-twelfth of the sum of Buyer's Monthly Withdrawal Quantities, adjusted for delivery deficiencies.
MINIMUM MONTHLY BILL. Demand Charge.
DAILY AND MONTHLY WITHDRAWAL QUANTITY. Maximum volume Seller is obligated to deliver on any day or month during the Withdrawal Period.
WINTER WITHDRAWAL QUANTITY. Maximum volume of top storage gas Seller is obligated to deliver during the Withdrawal Period, equal to sum of Monthly Withdrawal Quantities.
DELIVERY DEFICIENCY CHARGE. 69.39¢ per Mcf credit for delivery deficiency below the lesser of Buyer's Daily Withdrawal Quantity or the quantity Buyer was entitled to receive on that day.
BTU ADJUSTMENT. Metered volume adjusted pro rata each day for actual heat content variation from 1000 Btu per cu. ft.
HEAT CONTENT. Minimum 950 Btu per cu. ft.
MEASUREMENT BASE. 14.65 psia, 60°F.
EFFECTIVE DATE. February 1, 1985

LS SERIES, STORAGE SERVICE

AVAILABILITY. To DMQ-1 or G-1 Buyers executing a service agreement.
SERVICE. Firm, during Withdrawal Period beginning December 1 and ending next March 31. Buyer to make available a quantity of gas up to the Winter Withdrawal Quantity for injection into top storage during the April 1 to November 30 Injection Period.
RATE.

Rate Schedule	Charge Per Mcf: Monthly Demand 1/	Injection Deficiency 2/	Delivery Deficiency 3/
LS-1	$ 3.44	$ 3.54	41.00¢
LS-2	$ 2.75	$ 3.46	33.00¢
LS-3	$ 2.75	— —	33.00¢

1/ Charge per Mcf of Daily Withdrawal Quantity.
2/ Charge per Mcf for deliveries at Seller's option to make up for Buyer's injection deficiencies.
3/ Credit per Mcf for Seller's delivery deficiency below the lesser of Buyer's Daily Withdrawal Quantity or the quantity Buyer was entitled to receive on that day.

MINIMUM MONTHLY BILL. Demand Charge.
DAILY WITHDRAWAL QUANTITY. Maximum volume Seller is obligated to deliver on any day during the Withdrawal Period.
WINTER WITHDRAWAL QUANTITY. Maximum volume of top storage gas Seller is obligated to deliver during the Withdrawal Period, equal to 100 times the Daily Withdrawal Quantity.
BTU ADJUSTMENT. Metered volume adjusted pro rata each day for actual heat content variation from 1000 Btu per cu. ft.
HEAT CONTENT. Minimum 950 Btu per cu. ft.
MEASUREMENT BASE. 14.65 psia, 60°F.
EFFECTIVE DATE. February 1, 1985

NORTHWEST PIPELINE CORPORATION

LS-1, LIQUEFACTION—STORAGE GAS SERVICE

AVAILABILITY. To ODL-1 or DS-1 Buyers who have executed a service agreement.
SERVICE. Firm, storage service consisting of liquefaction of natural gas, the storage of such liquefied gas and the vaporization and delivery of such gas during Vaporization Period of November 1 through March 31.
Seller to deliver volumes at Buyer's election up to the specified Storage Demand Volume (maximum volume Seller is obligated to deliver on any one day), and Buyer's Storage Capacity Volume (volume Seller is obligated to liquefy, store and keep available during any single Vaporization Period.)
RATE.
Demand Charge: 3.223¢ per month per therm of Storage Demand Volume
Capacity Charge: 3.603¢ per month per therm of Storage Capacity Volume
Liquefaction Charge: 1.020¢ per therm of gas liquefied and stored for Buyer's account.
Vaporization Charge: 0.271¢ per therm of gas vaporized and delivered to Buyer.
MINIMUM MONTHLY BILL. Sum of the Demand Charge and the Capacity Charge.
HEAT CONTENT. Minimum 985 Btu per cu. ft.
MEASURMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. June 4, 1985

SGS-1, STORAGE GAS SERVICE

AVAILABILITY. To ODL-1 Buyers from October 1 through April 30, who have executed a service agreement.
SERVICE. Firm, up to Contract Demand and Seasonal Contract Quantity.
RATE.
Demand Charge. 22.860¢ per therm per month of Contract Demand for each month of October through April.
Commodity Charge. 32.377¢ per therm delivered.
Seasonal Demand Charge. 1.326¢ per therm of Seasonal Contract Quantity per month of each month of October through April.
Demand Charge Credit. 22.860¢ of owned Storage Demand per month for each month of October through April.
Seasonal Demand Charge Credit. 0.582¢ per therm of Owned Storage Seasonal Quantity per month for each month of October through April.

SECTION 10 OPTION. Buyer has the option to have Seller cause gas to be injected for Buyer's account in the Jackson Prairie Storage Project up to Buyer's Seasonal Contract Quantity. A Buyer having exercised this option may terminate the option by giving at least 24-months notice. When the option is exercised a different rate is applicable.
MINIMUM BILL. Sum of Demand and Seasonal Charges plus Credit Amounts for Owned Storage.
CONTRACT DEMAND. Seller's maximum daily delivery obligation to Buyer. Seller's daily delivery obligation (Contract Demand) is reduced 1% for each 1% reduction of Buyer's remaining Seasonal Contract Quantity below 60%. Deliveries in excess of Contract Demand at Seller's option, but not in excess of Seasonal Contract Quantity.
SEASONAL CONTRACT QUANTITY. The number of therms Seller is obligated to deliver from October 1 through April 30.
OWNED STORAGE DEMAND. Buyer's undivided interest in the total contract demand of the Jackson Prairie Storage Project.
HEAT CONTENT. Minimum 985 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. July 1, 1985

TENNESSEE GAS PIPELINE COMPANY, A DIVISION ON TENNECO INC.*

SS-E, STORAGE SERVICE

AVAILABILITY. Zones 4 (Northern) and 5 (New York), to CD Buyers contracting for a specified Winter Storage Quantity and Daily Storage Quantity.
SERVICE. Firm. Seller to be ready to deliver at all times volumes requested by Buyer up to the Daily Storage Quantity, provided that during the period from November 1 to the last day of February Buyer's withdrawals do not exceed 85% of Buyer's Winter Storage

*COMPANY HAS FILED NEW MAJOR RATES SHOWN IN "SUSPENDED SECTION."

Quantity. Buyer's Winter Storage Quantity is not to be less than 30 nor more than 150 times the Daily Storage Quantity. The amount of gas in storage for Buyer's account at any time shall not exceed Buyer's Winter Storage Quantity

IATE. For each month Buyer shall pay the sum of the following (excludes cost of gas):
Deliverability Charge: $4.64 per Mcf of Daily Storage Quantity
Space Charge: 3.17¢ per Mcf of Winter Storage Quantity
Injection Charge: 4.15¢ per Mcf designated by Buyer in any month for injection
Withdrawal Charge: 4.14¢ per Mcf
(Buyer also pays either CD-4 Commodity Charge of 29.42¢ per Mcf and Gas Charge of 255.08¢ per Dth or CD-5 Commodity Charge of 33.66¢ per Mcf and Gas Charge of 258.05¢ per Dth at time gas is delivered to Buyer.)

AINIMUM MONTHLY BILL. Sum of Deliverability Charge and the Space Charge

EXCESS WITHDRAWAL CHARGE. $1.4388 per Mcf of gas requested by Buyer and delivered by Seller, at its option, in excess of Seller's obligation. (Buyer also pays the gas charge.)

JNAUTHORIZED OVERRUN. Charge of $1.8478 per Mcf for unauthorized takes in excess of the Daily Storage Quantity. (Buyer also pays the gas charge.)

IEAT CONTENT. Minimum 967 Btu per cu. ft.

IEASUREMENT BASE. 14.73 psia, 60°F

EFFECTIVE DATE. August 15, 1985

-NE, STORAGE SERVICE

AVAILABILITY. To CD-6 (New England Zone) Buyers contracting for a specified Winter Storage Quantity and Daily Storage Quantity.

SERVICE. Firm. Seller to be ready to deliver at all times volumes requested by Buyer up to the Daily Storage Quantity, provided that during the period from November 1 to the last day of February, Buyer's withdrawals do not exceed 85% of Buyer's Winter Storage Quantity. Buyer's Winter Storage Quantity is not to be less than 30 nor more than 150 times the Daily Storage Quantity. The amount of gas in storage for Buyer's account at any time shall not exceed Buyer's Winter Storage Quantity.

RATE. For each month Buyer shall pay the sum of the following (excludes the cost of gas):
Deliverability Charge: $5.61 per Mcf of Daily Storage Quantity
Space Charge: 3.17¢ per Mcf of Winter Storage Quantity
Injection Charge: 4.15¢ per Mcf designated by Buyer in any month for injection
Withdrawal Charge: 4.14¢ per Mcf
(Buyer also pays CD-6 Commodity Charge of 37.58¢ per Mcf and Gas Charge of 261.29¢ per Mcf at time gas is delivered to Buyer.)

AINIMUM MONTHLY BILL. Sum of Deliverability Charge and the Space Charge

EXCESS WITHDRAWAL CHARGE. $1.6073 per Mcf of gas requested by Buyer and delivered by Seller, at its option, in excess of Seller's obligation. (Buyer also pays the gas charge.)

JNAUTHORIZED OVERRUN. Charge of $2.0732 per Mcf for unauthorized takes in excess of the Daily Storage Quantity. (Buyer also pays the gas charge.)

IEAT CONTENT. Minimum 967 Btu per cu. ft.

IEASUREMENT BASE. 14.73 psia, 60°F

EFFECTIVE DATE. August 15, 1985

TEXAS EASTERN TRANSMISSION CORPORATION

, STORAGE SERVICE

AVAILABILITY. Entire system, for Contract Year November 1 through October 31.

ERVICE. Firm, up to Storage Volume and Maximum Daily Quantity of Storage Service. Storage Volume not less than 50 times Maximum Daily Quantity of Storage Service.

IATE
Demand Charge: $2.48 per Dth of MDQ of Storage Service per month.
Space Charge: 1.0¢ per Dth of Storage Volume per month
Delivery Charge: 2.5¢ per Dth of Storage Service gas delivered

PURCHASE IN LIEU OF RETURN CHARGE. $2.8970 per Dth

MINIMUM BILL. Sum of Demand Charges and Space Charges

EXCESS WITHDRAWAL CHARGE. For withdrawals in excess of either Maximum Daily Quantity or Storage Volume, 57.01¢ per Dth for deliveries from Buyer's storage balance, $3.4671 for deliveries not from Buyer's storage balance.

HEAT CONTENT. Minimum 967 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F

EFFECTIVE DATE. September 1, 1985

X-28, STORAGE SERVICE

AVAILABILITY. Transcontinental Gas Pipe Line Corporation

SERVICE. Storage. Withdrawals of scheduled Maximum Daily Quantities from Oakford Storage Field made during period November 16 through April 15, to be returned by Buyer during succeeding period April 16 through November 15 of each year.

RATE
Annual Demand Charge: $54.00 per Dth of MDQ
Commodity Charge: 2.00¢ per Dth withdrawn from or returned to storage

HEAT CONTENT. Minimum 1000 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F

EFFECTIVE DATE. September 1, 1985

SS-II, STORAGE SERVICE

AVAILABILITY. To any Buyer executing an agreement for Storage hereunder and which has an Annual Quantity Entitlement listed under Section 12.3A of the General Terms and Conditions of the tariff. Storage Service is based on service rendered to Seller by Consolidated Gas Supply Corporation under Rate Schedule GSS.

SERVICE. Firm up to MDWQ subject to capacity being available on Seller's system for transportation of Storage Gas

	Zone			
RATE	A	B	C	D
Demand	$ .81	$ .81	$ .81	$ .81
Firm Demand	$ 9.4660	$ 9.4660	$ 9.4660	$ 9.4660
Space	3.49¢	3.49¢	3.49¢	3.49¢
Injection Charge	1.0¢	1.0¢	1.0¢	1.0¢
Withdrawal Charge	4.34¢	4.34¢	4.34¢	4.34¢

MINIMUM MONTHLY CHARGE. Sum of MDWQ Charge, the Firm Demand Charge, and the Space Charge

ANNUAL CONSOLIDATED GSS BILLING ADJUSTMENT. Any additional charges or reduction in charges from Consolidated under GSS shall be flowed through.

HEAT CONTENT. Minimum 967 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F

EFFECTIVE DATE. September 1, 1985

ISS-III, INTERIM STORAGE SERVICE

AVAILABILITY. To any distribution or pipeline company executing an agreement for storage service and which has an Annual Quantity Entitlement listed in the General Terms and Conditions. This service is based upon storage service rendered to Seller on a best efforts basis by Consolidated Gas Transmission Corporation. Service is for a limited term.

SERVICE. Service is subject to interruption to extent storage service to Seller by Consolidated is interrupted. When capacity is available on Seller's system Seller will withdraw quantities at Buyer's request up to Buyer's Annual Storage Quantity in daily quantities up to Buyer's Maximum Daily Withdrawal Quantity. Such daily service shall be firm.

	Zone			
RATE	A	B	C	D
Demand	$ 81	$ 81	$ 81	$ 81
Space	$ 0349	$ 0349	$ 0349	$ 0349
Injection	$ 01	$ 01	$ 01	$ 01
Withdrawal	$ 3384	$ 1614	$ 0857	$ 1616

MINIMUM MONTHLY BILL. The sum of the Demand Charge and the Space Charge.
HEAT CONTENT. Minimum 967 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985

TRANSCONTINENTAL GAS PIPE LINE CORPORATION

GSS, GENERAL STORAGE SERVICE

AVAILABILITY. To CD, G and OG Buyers for purchase of storage service other than service rendered under Rate Schedule S-2.
SERVICE. Storage withdrawals of scheduled quantities of firm gas previously stored for account of Buyer. Maximum daily withdrawal quantity limited to Buyer's Storage Demand and total withdrawal limited to Storage Capacity Quantity (top storage) of Buyer. The Storage Capacity Quantity not to be more than 110 nor less than 50 times Buyer's Storage Demand and shall be specified in service agreement.
RATE.
(a) Demand Charge: $2.63 per month per Dth of Storage Demand
(b) Storage Capacity Quantity Charge: 1.7¢ per month per Dth of Storage Capacity Quantity
(c) Volume Injected or Withdrawn Charge: 1.0¢ per Dth delivered into or withdrawn from storage
MINIMUM BILL.
Monthly—Sum of Demand Charge and Storage Capacity Quantity Charge.
Minimum Annual Quantity Injected and Withdrawn Charges—During each storage year, payment for a minimum injection quantity equal to 65% of Buyer's Storage Capacity Quantity at 1.0¢ per Dth, and payment of the same amount for minimum withdrawal quantity.
CREDIT CHARGE. 397.6¢ per Dth of gas Seller has injected into storage and upon request credits to Buyer's Storage Gas Balance.
EXCESS DELIVERY CHARGE.
71.5¢ per Dth for gas from Buyer's Balance.
$4.701 per Dth for gas not from Buyer's Balance.
STORAGE YEAR. 12 months ending March 31
HEAT CONTENT. Not less than 980 Btu per cu. ft. nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985

S-2, STORAGE SERVICE—ZONE 3

AVAILABILITY. Zone 3, to specified CD-3 (Contract Demand) Buyers.
SERVICE. Storage Withdrawals of scheduled Maximum Daily Quantities from Oakford Storage Field made during period November 16 through April 15 to be returned by Buyer during succeeding period April 16 through November 15 of each year.
RATE.
Demand Charge: $4.57034 per month per Dth of Contract Storage Demand
Delivered from Storage Charge: 357.21¢ per Dth delivered to Buyer from Storage
Return to Seller Charge: 2.0¢ per Dth nominated by Buyer for return to Seller
DEMAND CHARGE ADJUSTMENT. 36.3¢ per Dth credit for delivery deficiency below Buyer's requested quantity.
MINIMUM MONTHLY BILL. Demand Charge
HEAT CONTENT. Not less than 980 Btu per cu. ft. nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985

LG-A, LIQUEFIED NATURAL GAS STORAGE SERVICE

AVAILABILITY. To any utility or gas distribution agency purchasing from Seller under other rate schedules, except ACQ and PS, for delivery at points upstream of Carlstadt, New Jersey.
SERVICE. Firm, storage service consisting of liquefaction of natural gas, the storage of such liquefied gas and the gasification and delivery of such gas during withdrawal period of November 1 through March 31.
Seller to deliver quantities at Buyer's election up to the specified Liquefaction Demand (maximum quantity Seller is obligated to deliver on any day), and Buyer's Liquefaction Capacity Quantity (quantity Seller is obligated to liquefy, store and keep available during any single Withdrawal Period).
RATE.
(a) Demand Charge: 21.6¢ per month per Dth of Liquefaction Demand
(b) Capacity Charge: 28.3¢ per month per Dth of Liquefaction Capacity Quantity
(c) Delivery Charge: 21.5¢ per Dth delivered from storage
MINIMUM MONTHLY BILL. Sum of the Demand Charge and the Capacity Charge.
EXCESS DELIVERY CHARGE.
$4.13 per Dth for gas from Buyer's Balance
$8.11 per Dth for gas not from Buyer's Balance
HEAT CONTENT. Not less than 980 Btu per cu. ft. nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985

WSS, WASHINGTON STORAGE SERVICE

AVAILABILITY. To any utility or distributor purchasing from Seller under CD, G or OG Rate Schedules
SERVICE. Storage withdrawals of scheduled quantities of firm gas stored for Buyer, up to Storage Gas Balance. Total withdrawal limited to Storage Gas Balance. Buyer to nominate storage injection volumes in the ratio of .7325 Mcf of Base gas to one (1) Mcf top storage gas.
RATE.
(a) Storage Capacity Quantity Charge: 2.63¢ per month per Dth of Storage Capacity Quantity
(b) Quantity Withdrawal Charge: 3.9¢ per month per Dth for gas withdrawn from storage
MINIMUM MONTHLY BILL. Storage Capacity Quantity Charge.
DEVELOPMENT PERIOD. Beginning the day of initial injection extending through April 1, 1977
DAILY WITHDAWAL QUANTITY. Maximum daily quantity Seller can withdraw from storage for Buyer is limited by operating conditions, Seller's capacity and Buyer's Storage Gas Balance as follows:

Storage Gas Balance As a Percent of Storage Capacity Quantity	Average Daily Withdrawal As a Fraction of Storage Capacity Quantity
0-20%	1/155
21-40%	1/125
41-60%	1/105
61-80%	1/95
81-100%	1/85

HEAT CONTENT. Not less than 980 nor more than 1100 Btu per cu. ft.
MEASUREMENT BASE. 14.73 psia, 60°F.
EFFECTIVE DATE. September 1, 1985

LSS, LEIDY STORAGE SERVICE

AVAILABILITY. To any person, company or agency for purchase of storage service.
SERVICE. Firm up to scheduled injection and withdrawal quantities, provided it is subject to interruption due to force majeure or or to partial interruption during the limited-term storage service phase of Seller's agreement for storage service with Consolidated Gas Transmission Corporation, a supplier of a portion of the storage services which underlie services by Seller.
RATE.
Demand Charge: $7.87 per month per dt of Storage Demand
Storage Capacity Quantity Charge: 5.16¢ per month per dt of Storage Capacity Quantity
Quantity Injection Charge: 0.67 per dt injected into storage
Quantity Withdrawn Charge: 0.67¢ per dt withdrawn from storage

MINIMUM MONTHLY BILL. Sum of the Demand Charge and the Storage Capacity Charge.

INJECTIONS INTO STORAGE. During the injection period from April 1 through October 31 Seller shall endeavor to inject on any day as much of Buyer's nomination for such day as operating conditions permit. However, Seller is obligated to inject on any day at Buyer's request, at least 1/180 of Buyer's Storage Capacity Quantity until such time as Buyer's Storage Gas Balance is equal to ½ of Buyer's Storage Capacity Quantity and thereafter at least 1/214 of Buyer's Storage Capacity Quantity.

WITHDRAWALS FROM STORAGE. During the withdrawal period from November 1 through March 31 Seller shall endeavor to withdraw and deliver, on any one day, up to, but not exceeding, Buyer's Storage Demand. Buyer shall schedule withdrawals of gas from storage for the period November 1 through December 31 in a manner which shall result in a Storage Gas Balance, for Buyer, on January 1, that shall not exceed 70% of Buyer's Storage Capacity Quantity.

HEAT CONTENT. Average daily heating value not less than 980 Btu per cu. ft., nor more than 1100 Btu per cu. ft.

MEASUREMENT BASE. 14.73 psia, 60°F.

EFFECTIVE DATE. September 1, 1985

APPENDIX V

CONSUMERS' RATE DETERMINATIONS

Exhibits filed by Consumers' in March, 1985 in E.B.R.O. 403 for test year ended September 30, 1986 include particulars of its storage operation. References to exhibits follow the code used by Consumers'.

On Exhibit G4.3.1 a summary of month-end balances and monthly averages for volume and investment of gas in storage is provided. Supporting this summary, on G4.3.2 and G4.3.3, are particulars by months in the test year of storage facilities used by Consumers'. The peak level for volumes and investment on a month-end basis occurs at October 31. Of the total volume of 2,072.8 10^6m^3 at October 31, 1985, storage by location is shown on G4.3.2:

Tecumseh	1,671.4 10^6m^3
Union	365.0
Consumers' owned storage pools	36.4
TOTAL	2,072.8

From this comparison it is seen that storage facilities owned directly by Consumers' cover three pools and amounts to less than 2% of its total storage requirements.

Particulars of Tecumseh and Union storage and transportation costs forecast by Consumers' for the test year ended September 30, 1986 are shown on Exhibit F3.1.1. These are summarized as follows:

	$ Millions
Tecumseh Gas Storage Ltd.	
Storage	13.9
Union Gas Limited	
Storage	4.9
Transportation	31.0
Total Union	35.9
TOTAL	$49.8

Particulars of contract volumes/levels in effect for the test year for purchases by type of service from TransCanada PipeLines; for storage by Tecumseh, and for storage and transportation by Union are provided on Exhibit F5.1.9.

For Consumers' own pools the cost of storage is a small component of their overall storage costs. On Exhibit F1.3.2, operating and maintenance costs are estimated at $100,000 for the year ended September 30, 1986. The investment in underground storage plant during the test year is $2.6 million. After deduction of accumulated depreciation of $1.1 million, the net average investment is $1.5 million. These amounts are shown on Exhibit G2.1.1 and G2.1.3.

THE CONSUMERS' GAS COMPANY LTD.
and its consolidated subsidiary companies,
Consumers Marketing Company Limited, Consumers' Realty Limited and Underwater Gas Developers Limited

As at or year(s) ending September 30	1986	Historical	
		Forecasted	X

EXHIBIT	SCHEDULE	PAGE
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G4.3.1
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GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
SEPTEMBER 30.

ITEM NO.		COL. 1 VOLUMES 10**6 M**6	COL. 2 TOTAL ($MILLIONS)
	ALL STORAGE POOLS		
1.1	OCTOBER 1	2008.1	307.6
1.2	OCTOBER 31	2072.8	319.6
1.3	NOVEMBER 30	2038.5	316.5
1.4	DECEMBER 31	1710.4	265.2
1.5	JANUARY 31	1079.8	166.7
1.6	FEBRUARY 28	582.1	89.5
1.7	MARCH 31	200.6	29.0
1.8	APRIL 30	153.1	25.2
1.9	MAY 31	389.3	62.2
1.10	JUNE 30	741.8	116.8
1.11	JULY 31	1179.2	183.0
1.12	AUGUST 31	1616.4	249.4
1.13	SEPTEMBER 30	1977.4	305.3
1.	AVERAGE OF MONTHLY AVERAGES	1146.4	177.5

PHYSICAL STORAGE PIPE ACTIVITIES
1985 - 1986 BUDGET
$10^6 m^3$

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
	October'85	November'85	December'85	January'86	February'86	March'86	April'86	May'86	June'86	July'86	August'86	September'86
TECUMSEH												
Opening Balance	1,632.4	1,671.4	1,658.9	1,418.8	901.2	480.0	148.4	92.5	290.8	587.0	954.4	1,316.5
In	39.0	-	-	-	-	-	15.0	198.3	296.2	367.4	362.1	296.1
Out	-	(12.5)	(240.1)	(517.6)	(421.2)	(331.6)	(70.9)	-	-	-	-	-
Closing Balance	1,671.4	1,658.9	1,418.8	901.2	480.0	148.4	92.5	290.8	587.0	954.4	1,316.5	1,612.6
[illegible]												
Opening Balance	110.3	365.0	345.0	260.0	150.0	75.0	25.0	35.0	73.0	129.3	199.3	274.3
In	25.7	-	-	-	-	-	20.0	38.0	56.3	70.0	75.0	65.0
Out	-	(20.0)	(85.0)	(110.0)	(75.0)	(50.0)	(10.0)	-	-	-	-	-
Closing Balance	365.0	345.0	760.0	150.0	75.0	25.0	35.0	73.0	129.3	199.3	274.3	339.3
SOUTH SOUND												
Opening Balance	0.1	0.1	-	**	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
In	-	-	**	**	**	**	-	-	-	-	-	-
Out	-	(0.1)	-	-	-	-	-	-	-	-	-	-
Closing Balance	0.1	-	**	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SHERIDAN												
Opening Balance	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8
In	-	-	-	-	-	-	-	-	-	-	-	-
Out	**	**	**	**	**	**	**	**	**	**	**	(0.1)
Closing Balance	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
CROWLAND												
Opening Balance	12.7	12.7	12.2	11.7	11.2	11.2	12.7	12.7	12.7	12.7	12.7	12.7
In	-	-	1.0	1.5	1.5	2.0	-	-	-	-	-	-
Out	-	(0.5)	(1.5)	(2.0)	(1.5)	(0.5)	-	-	-	-	-	-
Closing Balance	12.7	12.2	11.7	11.2	11.2	12.7	12.7	12.7	12.7	12.7	12.7	12.7
LEEPFROG												
Opening Balance	22.7	22.7	21.5	19.0	16.5	15.0	13.5	12.0	12.0	12.0	12.0	12.0
In	-	-	-	-	-	-	-	-	-	-	-	-
Out	-	(1.2)	(2.5)	(2.5)	(1.5)	(1.5)	(1.5)	-	-	-	-	-
Closing Balance	22.7	21.5	19.0	16.5	15.0	13.5	12.0	12.0	12.0	12.0	12.0	12.0
TOTAL												
Opening Balance	2,008.1	2,072.8	2,038.5	1,710.4	1,079.8	582.1	200.5	153.1	389.4	741.9	1,179.3	1,616.4
In	64.7	-	1.0	1.5	1.5	2.0	35.0	236.3	352.5	437.4	437.1	361.1
Out	**	(34.3)	(329.1)	(632.1)	(499.7)	(383.6)	(82.4)	**	**	**	**	(0.1)
Closing Balance	2,072.8	2,038.5	1,710.4	1,079.8	582.1	200.5	153.1	389.4	741.9	1,179.3	1,616.4	1,977.4

** Lost due to rounding

EXHIBIT G4
SCHEDULE 3
PAGE 2 of 3
G4.3.2
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GAS IN STORAGE
MONTH END BALANCE COSTS
Year Ending September 30, 1986

(Millions) $10^6 m^3$

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
		October'85	November'85	December'85	January'86	February'86	March'86	April'86	May'86	June'86	July'86	August'86	September'86
Storage Opening Commodity Cost	$	288 8	298 1	292 9	245 1	155 7	85 1	29 0	22 1	55 9	107 0	169 6	232 1
FIFO Injections	$	94 9	123 7	123 4	114 4	104 8	103 4	104 8	100 3	105 2	110 1	111 5	106 8
FIFO Withdrawals	$	(90 6)	(128 9)	(171 2)	(203 8)	(174 6)	(159 5)	(111 7)	(74 5)	(54 1)	(47 5)	(49 0)	(54 5)
Storage Closing Commodity Cost	$	298 1	292 9	245 1	155 7	85 1	29 0	22 1	55 9	107 0	169 6	232 1	284 4
Accrued Demand Charges	$	18 8	21 5	24 2	27 0	29 9	32 7	3 1	6 1	9 2	12 3	15 3	18 4
Accrued In Charges	$	2 7	2 7	2 7	2 7	2 7	2 7	**	0 2	0 6	1 1	2 0	2 7
Amortized Demand Charges	$		(0 6)	(6 3)	(17 3)	(26 0)	(32 7)	-	-	-	-	-	-
Amortized In Charges	$		**	(0 5)	(1 4)	(2 2)	(2 7)	-	-	-	-	-	-
Storage Closing Balance	$	319 6	316 5	265 2	166 7	89 5	29 0	25 2	62 2	116 8	183 0	249 4	305 5
Storage Physical Volumes	$10^6 m^3$	2,072 8	2,038 5	1,710 4	1,079 8	582 1	200 5	153 1	389 4	741 9	1,179 1	1,616 4	1,977 4

** Lost due to rounding

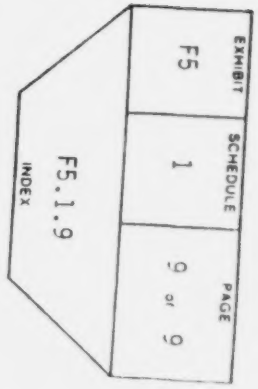
EXHIBIT G4
SCHEDULE 3
PAGE 3 of 3
INDEX G4.3.3

[illegible] AND PROPOSED CONTRACT LEVELS
FISCAL YEAR 1986

Col. 1	Col. 2		Col. 3	Col. 4
Contract Name	Delivery Area	Effective Dates	Daily Volume 10^3m^3	(100% Load Factor) Annual Volumes 10^3m^3
Contract Demand Service	CDA	11/01/80 - 10/31/95	12,505	4,564,325
	EDA	11/01/82 - 10/31/95	4,485	1,637,025
Annual Contract Quantity	SWDA/CDA	11/01/85 - 03/31/86	6,079	918,000
		04/01/86 - 10/31/86	6,435	1,377,000
Winter Peaking Service(1)	CDA	11/01/85 - 04/15/86	708	7,080
	EDA	11/01/85 - 04/15/86	2,125	21,250
Tecumseh Gas Storage				
- Annual Turnover Volume (ATV)		04/01/82	-	1,670,000
- Storage Demand		04/01/82	28,500	-
Union Gas Storage				
- Space		04/01/84	-	365,000
- Demand		04/01/84	5,850	-
Union Gas Transportation				
- Demand With Compression		11/01/84	13,500	-
- Demand Without Compression		11/01/84	25,500	-
Oakville Compression Service				
- Firm		04/01/85 - 03/31/86	7,300	-
- Best Efforts		04/01/85 - 03/31/86	8,100	-

Note:

(1) Proposed



THE CONSUMERS' GAS COMPANY LTD.
and its consolidated subsidiary companies,
Consumers Marketing Company Limited, Consumers' Realty Limited and Underwater Gas Developers Limited

As at or year(s) ending September 30	1986	Historical	
		Forecasted	X

EXHIBIT	SCHEDULE	PAGE
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F3.1.1
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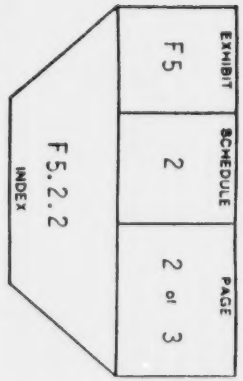
STORAGE AND TRANSPORTATION COSTS
Year Ending September 30, 1986

Item No.		Charges ($Millions)
	TECUMSEH GAS STORAGE LTD.	
	Demand	
1.1.1	ATV	7.5
1.1.2	Peak Day	4.3
	Commodity	
1.1.3	Storage - In	0.3
1.1.4	Storage - Out	0.3
1.1.5	Fuel Usage	1.5
1.	Total Tecumsen Payments	13.9
	UNION GAS LTD.	
	Storage	
2.1.1	Space	2.1
2.1.2	Peak Day	2.2
2.1.3	Storage - In	0.3
2.1.4	Storage - Out	0.3
2.1	Total Storage	4.9
	TRANSPORTATION	
	Demand	
2.2.1	With Compression	8.1
2.2.2	Without Compression	12.5
2.2.3	Dehydration	1.5
2.2.4	STS	0.9
	Commodity	
	Dawn to Oakville	
2.2.5	With Compression	3.2
2.2.6	Without Compression	2.3
	Oakville to Dawn	
2.2.7	With Compression	1.7
2.2.8	STS - Union	0.3
2.2.9	Local Production	0.3
2.2.10	YCRR Adjustment	0.2
2.2	Total Transportation	31.0
2.	Total Union Payments	35.9

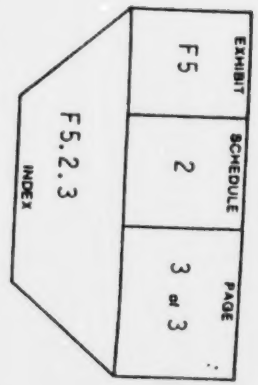
C - PHYSICAL GAS SEIDOUT TO OPERATION
(FIFO STORAGE WITHDRAWAL)
(10**3 M**3)

	OCT.	NOV.	DEC.	JAN.	FEB.	MARCH
PURCHASES & PRODUCTION						
TCPL - CDA CD	449486.0	405266.0	382839.0	367090.0	344577.0	403635.0
ACQ	128278.0	324885.0	303463.0	228463.0	204212.0	160163.0
WPS	0.0	0.0	708.0	2832.0	2124.0	1416.0
ACQ MAKE-UP	7319.9	0.0	0.0	0.0	0.0	0.0
OTHER	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CDA	585083.9	730151.0	687010.0	598385.0	550913.0	565214.0
TCPL - EDA CD	77204.0	104434.0	143851.0	159600.0	131143.0	123055.0
WPS	0.0	0.0	2125.0	8500.0	6375.0	4250.0
TOTAL EDA	77204.0	104434.0	145976.0	168100.0	137518.0	127305.0
TOTAL TCPL	662287.9	834585.0	832986.0	766485.0	688431.0	692519.0
OTHER ONT. SUPPLIERS	13656.9	10250.0	10160.0	10150.0	9900.0	9900.0
PRODUCTION GAS	17995.0	18032.0	18287.0	14833.0	13512.0	14037.0
TOTAL PURCH. & PROD. (10**3 M**3)	693939.8	862867.0	861433.0	791468.0	711843.0	716456.0
STORAGE POOL ACTIVITIES						
TECUMSEH (IN)	-38966.0	0.0	0.0	0.0	0.0	0.0
OUT	0.0	12481.0	240045.0	517597.0	421213.0	331550.0
UNION (IN)	-25686.8	0.0	0.0	0.0	0.0	0.0
OUT	0.0	20000.0	85000.0	110000.0	75000.0	50000.0
OWEN SOUND (IN)	0.0	0.0	-25.0	-25.0	-25.0	-25.0
OUT	0.0	101.0	0.0	0.0	0.0	0.0
SHERKSTON (IN)	0.0	0.0	0.0	0.0	0.0	0.0
OUT	22.0	20.0	21.0	19.0	20.0	20.0
CROWLAND (IN)	0.0	0.0	-1000.0	-1500.0	-1500.0	-2000.0
OUT	0.0	500.0	1500.0	2000.0	1500.0	500.0
LEEPFROG (IN)	0.0	0.0	0.0	0.0	0.0	0.0
OUT	0.0	1200.0	2500.0	2500.0	1500.0	1500.0
TOTAL (IN)	-64652.8	0.0	-1025.0	-1525.0	-1525.0	-2025.0
TOTAL OUT	22.0	34302.0	329066.0	632116.0	499233.0	383570.0
TOTAL STORAGE ACTIVITIES (10**3 M**3)	-64630.8	34302.0	328041.0	630591.0	497708.0	381545.0
TOTAL CDA & EDA SEIDOUT (10**3 M**3)	629309.0	897169.0	1189474.0	1422059.0	1209551.0	1098091.0



- [illegible] SENDOUT TO OPERATION
(FIFO STORAGE WITHDRAWAL)
(10**3 M**3)

PURCHASES & PRODUCTION	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	TOTAL
TCPL - CDA CD	422678.0	469750.0	466518.0	488588.0	487402.0	460429.0	5148258.0
ACQ	193038.0	199472.0	193037.0	199472.0	02137.0	78380.0	2295000.0
WPS	0.0	0.0	0.0	0.0	0.0	0.0	7090.0
ACQ MAKE-UP	0.0	0.0	0.0	13728.0	140945.0	125782.0	287774.9
OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CDA	615716.0	669222.0	659555.0	701788.0	710484.0	664591.0	7738112.9
TCPL - EDA CD	87022.0	56940.0	43182.0	38102.0	39288.0	49271.0	1053092.0
WPS	0.0	0.0	0.0	0.0	0.0	0.0	21250.0
TOTAL EDA	87022.0	56940.0	43182.0	38102.0	39288.0	49271.0	1074342.0
TOTAL TCPL	702738.0	726162.0	702737.0	739890.0	749772.0	713862.0	8812454.9
OTHER ONT. SUPPLIERS	9850.0	9665.0	8315.0	8315.0	8315.0	8565.0	117041.9
PRODUCTION GAS	14521.0	18438.0	18164.0	18503.0	19023.0	17925.0	203270.0
TOTAL PURCH. & PROD. (10**3 M**3)	727109.0	754265.0	729216.0	766708.0	777110.0	740352.0	9132766.8
STORAGE POOL ACTIVITIES							
TECUMSEH (IN)	-15000.0	-198266.0	-296198.0	-367420.0	-362192.0	-296057.0	-1574099.0
OUT	70968.0	0.0	0.0	0.0	0.0	0.0	1593854.0
UNION (IN)	-20000.0	-38000.0	-56314.0	-70000.0	-75000.0	-65000.0	-350000.8
OUT	10000.0	0.0	0.0	0.0	0.0	0.0	350000.0
OWEN SOUND (IN)	0.0	0.0	0.0	0.0	0.0	0.0	-100.0
OUT	0.0	0.0	0.0	0.0	0.0	0.0	101.0
SHERKSTON (IN)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OUT	21.0	22.0	22.0	22.0	24.0	20.0	253.0
CROWLAND (IN)	0.0	0.0	0.0	0.0	0.0	0.0	-6000.0
OUT	0.0	0.0	0.0	0.0	0.0	0.0	6000.0
LEEPFROG (IN)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OUT	1500.0	0.0	0.0	0.0	0.0	0.0	10700.0
TOTAL (IN)	-35000.0	-236266.0	-352512.0	-437420.0	-437192.0	-361057.0	-1930199.8
TOTAL OUT	82489.0	22.0	22.0	22.0	24.0	20.0	1960908.0
TOTAL STORAGE ACTIVITIES (10**3 M**3)	47489.0	-236244.0	-352490.0	-437398.0	-437168.0	-361037.0	30708.2
TOTAL CDA & EDA SENDOUT (10**3 M**3)	774598.0	518021.0	376726.0	329310.0	339942.0	379315.0	9163475.0



APPENDIX VI

TRANSCANADA PIPELINES RATE DETERMINATIONS

DEVELOPMENT OF UNIT COSTS
AND OTHER COSTS ANALYSIS
FOR TRANSPORTATION SERVICE

TransCanada PipeLines Limited

Net cost of transmission for year ended Sept. 30, 1984, ($000) per Tab 2, Schedule 1			1,128,764
Volume/distance units 10^6m^3 km, per Tab 3, Schedule 1, Sheet 11			80,141,191
Cost per 10^3m^3 - km			$.014085
Cost per 10^3m^3 - 100 km			$1.4085
	km Post		
Dawn	2613	Cost at $1.4085	$36.804/$10^3m^3$
Sheridan	3005	Cost at $1.4085	$46.325/$10^3m^3$
Average TCPL demand rate for Eastern Zone for C D Service at 100% Load factor, rates effective November 1, 1985 Per Union Schedule 4			$33.618/$10^3m^3$
Fixed Cost of Service to Gross Plant Gross Plant, Schedule 7, ($000)			3,370,819
Fixed Transmission costs, Tab 2, Schedule 1, ($000)			
Misc.		270	
Metering	10,420		
Less tax adjust.	(23,000)	12,580	12,850
Fixed transmission		906,103	
Less trans. by others		(145,131)	760,972
			773,822
% of Fixed Transmission Costs to Gross Plant		773,822 / 3,370,819	22.96%
to Net Plant		773,822 / 2,488,211	31.11%

Components of Cost of Service to Rate Base ($000)		
Rate Base, Schedule 7		2,581,360
Components (Tab 2, Schedule 1)	%	
Return at 14.92%	14.92	385,139
Income Taxes	4.91	126,734
Depreciation	3.59	92,738
Taxes - Other	1.28	33,076
Operation and Maintenance (fixed portion)	5.18	133,827
	29.88	771,514
Average Cost of Transmission per Union Gas Limited, per Exhibit K6, Schedule 3 in E.B.R.O. 405.2		
Average Cost of Transmission excluding Dawn compression. Cost per 10^3m^3 days per month for 228.94 km		$52.158
Rate for annual volume based on 100% load factor for 228.94 km		
$\frac{\$52.158 \times 12}{365}$		1.715
for 100 km		.749

TransCanada PipeLines Limited

Total Cost of Service Including Return
Twelve Months Ended September 30, 1984, As Adjusted

Line No.	Particulars	Booked	Adjustments	As Adjusted	Cost of Service Schedule Reference
	(a)	(b)	(c)	(d)	(e)
1	Cost of Gas Sold	$3,128,677,549	20,742,169	3,149,419,718	2.1
2	Transmission by Others	214,887,483	(27,521,917)	187,365,566	3.1
3	Operations & Maintenance (Ex. North Bay Shortcut)	236,341,500	86,634,959	322,976,459	
4	North Bay Shortcut	(35,543,658)	50,738,090	15,194,432	
5	Total Operations & Maintenance	200,797,842	137,373,049	338,170,891	4
6	Depreciation	96,907,895	(4,170,129)	92,737,766	7.9
7	Taxes Other than Income	32,872,055	204,145	33,076,200	5
8	Income Taxes	98,682,556	28,051,444	126,734,000	8
9	Reduction in Deferred Taxes	0	(23,000,000)	(23,000,000)	
10	Miscellaneous Deferred Items	11,154,055	(8,987,490)	2,166,565	9
11	Deduct: Other Operating Income	(6,320,583)	886,047	(5,434,536)	6
12	Total Cost of Service Excluding Return	$3,777,658,852	$123,577,318	$3,901,236,170	
13	Return at 14.92 %			385,138,903	7
14	Total Cost of Service Including Return			4,286,375,073	
15	Deduct: Miscellaneous Revenue			(12,479,131)	
16	Total Cost of Service			$4,273,895,942	

Cost of Service
Schedule 1

TransCanada PipeLines Limited

Utility Investment and Return
Twelve Months Ended September 30,1984, As Adjusted

Line No.	Particulars	As Booked	Adjustments	As Adjusted
	(a)	(b)	(c)	(d)
	Utility Investment			
1	Gross Plant	$3,290,158,872	80,661,057	$3,370,819,929
2	Accumulated Depreciation	(720,134,588)	(162,474,435)	(882,609,023)
3	Net Plant	2,570,024,284	(81,813,378)	2,488,210,906
4	Contributions in Aid of Construction	(5,993,288)	5,507,598	(485,690)
5	Total Plant	2,564,030,996	(76,305,780)	2,487,725,216
	Working Capital			
6	Cash	10,728,989	801,673	11,530,662
7	Materials and Supplies	27,319,211	853,438	28,172,649
8	Transmission Linepack	39,529,006	204,840	39,733,846
9	Prepayments and Deposits	3,572,869	(472,029)	3,100,840
10	Total Working Capital	81,150,075	1,387,922	82,537,997
	Deferred Costs			
11	Transmission by Others	(12,054,775)	34,781,696	22,726,921
12	Average Deferred Taxes	(75,868,922)	11,500,000	(64,368,922)
13	Miscellaneous Deferred Items	5,567,784	20,137,257	25,705,041
14	Other Deferred Items	(6,439,126)	10,681,175	4,242,049
15	North Bay Shortcut	10,227,018	12,564,618	22,791,636
16	Total Deferred Costs	(78,568,021)	89,664,746	11,096,725
17	Total Rate Base (excluding Alberta)	2,566,613,050	14,746,888	2,581,359,938
18	Return at 14.92 %			385,138,903

NEB 85-1-R-3

Trans Canada Pipelines Limited

Summary of Allocation Units as Adjusted

Line No.	Particulars	Fixed Allocation Units 12 Months Ending July 31, 1986		Variable Allocation Units 12 Months Ending July 31, 1986	
		10^{3}m^3	10^{3}m^3-km	10^{6}m^3	10^{6}m^3-km
	(a)	(b)	(c)	(d)	(e)
	Saskatchewan Zone				
1	Total Zone Sales as Adjusted (1)	510	258,794	70.0	34,787.3
	Manitoba Zone				
2	Total Zone Sales as Adjusted (1)	9,205	8,327,051	1,774.0	1,599,934.2
	Western Zone				
3	Total Zone Sales as Adjusted (1)	2,490	3,761,812	641.0	970,300.0
4	AOI Winter	8 (3)	12,086	3.0	4,541.2
5	Sales Including AOI	2,498	3,773,898	644.0	974,841.2
	Northern Zone				
6	Total Zone Sales as Adjusted (1)	5,375	12,732,803	1,656.0	3,920,405.8
7	AOI Winter - NDA	33 (3)	78,173	12.0	28,408.8
8	AOI Winter - SSMDA	41 (3)	97,125	15.0	35,510.9
9	Sales Including AOI	5,449	12,908,101	1,683.0	3,984,325.5
	Eastern Zone				
10	Total Zone Sales as Adjusted (1)	52,725	154,625,976	19,487.0	56,876,396.1
11	AOI Winter	756 (3)	2,231,128	276.0	809,987.2
12	AOI Summer	0	0	34.0	99,781.0
13	Sales Including AOI	53,481	156,857,104	19,797.0	57,786,164.3
14	Canadian Sales Including AOI	71,143	182,124,948	23,968	64,380,053
15	Export Sales as Adjusted (2)	24,086	30,822,609	6,110.4	7,865,259.4
16	System Sales Including AOI	95,229	212,947,557	30,078.4	72,245,311.9
17	Transportation as Adjusted (2)	15,762	17,226,245	4,013.0	4,919,252.4
18	Sales and Transportation Including AOI	110,991	230,173,802	34,091.4	77,164,564.3
19	T-Service as Adjusted (2)	3,146	9,634,136	983.0	2,976,627.3
20	Total System Including AOI	114,137	239,807,938	35,074.4	80,141,191.6

Notes: (1) See Tab 1, Schedule 1, Sheet 1 of 3
(2) See Tab 1, Schedule 1, Sheet 2 of 3
(3) Variable 10^{6}m^3 (column (d)) / 365 days

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS	KMPOST	DELIVERIES		PS & TWS	DIVERSION		OTHER	FIRM SALES	10^6m^3-KM
(a)	(b)	WINTER (c)	TOTAL (d)	(e)	FROM (f)	TO (g)	(h)	(i)	(j)
WESTERN ZONE									
NORTHERN & CENTRAL - WDA 309									
2301 KENORA	1132.28	30020.6	51662.0	0.0	3.8	1463.9	0.0	53122.0	60149.0
2302 DRYDEN	1260.50	29964.0	54855.9	0.0	4.1	1554.4	0.0	56406.2	71100.0
2303 THUNDER BAY	1577.60	222129.4	379707.1	0.0	28.3	10759.3	0.0	390438.1	615955.3
2304 RED ROCK	1667.44	40591.5	89015.9	0.0	6.6	2522.3	0.0	91531.6	152623.5
2305 NIPIGON	1676.22	2924.8	4511.1	0.0	0.3	127.8	0.0	4638.6	7775.3
2306 GERALDTON	1829.40	3637.7	5139.6	0.0	0.4	145.6	0.0	5284.9	9668.1
2307 ATIKOKEN	1428.83	11046.6	18049.3	0.0	1.3	511.4	0.0	18559.4	26518.2
2308 VERMILION BAY	1220.10	13469.3	24623.5	0.0	1.8	697.7	0.0	25319.4	30892.2
2309 LONG LAC	1862.03	8420.4	16441.7	0.0	1.2	465.9	0.0	16906.4	31480.2
2310 KEEWATIN	1126.76	550.8	747.1	0.0	0.1	21.2	0.0	768.2	865.6
2311 IGNACE	1360.02	976.0	1365.3	0.0	0.1	38.7	0.0	1403.9	1909.3
TOTAL		363731.1	646118.5	0.0	48.1	18308.3	0.0	664378.7	1008936.7
TOTAL ZONE		363731.1	646118.5	0.0	48.1	18308.3	0.0	664378.7	1008936.7

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS ($10^3 m^3$)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS	KMPOST	DELIVERIES		PS & TWS	DIVERSION		OTHER	FIRM SALES	$10^6 m^3$-KM
		WINTER	TOTAL		FROM	TO			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
NORTHERN ZONE									
NORTHERN & CENTRAL - NDA 413									
2401 HEARST	2072.47	11264.2	17526.8	0.0	1.4	1037.0	1344.9	19907.3	41257.2
2402 KAPUSKASING	2168.23	28119.2	63677.3	0.0	5.1	3767.6	4886.1	72325.8	156819.1
2403 SMOOTH ROCK FALLS	2231.22	12022.3	23286.6	0.0	1.9	1377.8	1786.8	26449.3	59014.3
2404 COCHRANE	2279.37	11649.1	17380.4	0.0	1.4	1028.3	1333.6	19741.0	44997.0
2405 IROQUOIS FALLS	2321.97	15818.4	38845.9	0.0	3.1	2298.4	2980.7	44121.9	102449.7
2406 TIMMINS	2332.22	96054.5	151329.2	0.0	12.2	8953.7	11611.8	171882.5	400867.8
2407 MATHESON	2356.33	1289.3	1763.0	0.0	0.1	104.3	135.3	2002.4	4718.4
2408 RAMORE	2369.81	759.5	951.2	0.0	0.1	56.3	73.0	1080.4	2560.3
2409 KIRKLAND LAKE	2414.25	16091.8	22914.4	0.0	1.8	1355.8	1758.3	26026.6	62834.7
2410 ENGLEHART	2454.57	3770.6	6675.7	0.0	0.5	395.0	512.2	7582.4	18611.5
2411 NEW LISKEARD	2491.48	8208.5	11525.9	0.0	0.9	682.0	884.4	13091.3	32616.8
2412 HAILEYBURY	2496.41	5336.0	7262.3	0.0	0.6	429.7	557.3	8248.7	20592.0
2413 SUDBURY	2637.60	131514.7	251166.2	0.0	20.2	14860.7	19272.5	285279.2	752452.4
2414 WEST FERRIS	2652.65	2725.5	4257.4	0.0	0.3	251.9	326.7	4835.6	12827.2
2415 WIDDIFIELD	2631.52	1420.0	2550.9	0.0	0.2	150.9	195.7	2897.4	7624.5
2416 TROUT LAKE	2645.74	21947.7	41458.5	0.0	3.3	2453.0	3181.2	47089.3	124586.1
2417 EARLTON	2467.23	728.6	1041.1	0.0	0.1	61.6	79.9	1182.5	2917.5
2418 BOSTON CREEK	2424.56	7893.7	15006.2	0.0	1.2	887.9	1151.5	17044.3	41325.0
2419 COLEMAN	2507.99	81.9	92.0	0.0	0.0	5.4	7.1	104.5	262.1
2420 ROUYN-NORANDA	2465.62	30829.0	54147.4	0.0	4.4	3203.7	4154.8	61501.6	151639.6
2421 MOONBEAM	2190.13	502.1	728.1	0.0	0.1	43.1	55.9	827.0	1811.2
2422 STRATHGAMI	2543.53	6468.0	12014.8	0.0	1.0	710.9	921.9	13646.6	34710.6
2423 MATTICE	2103.23	412.4	567.4	0.0	0.0	33.6	43.5	644.5	1355.5
2427 CALSTOCK	2038.32	948.3	1580.5	0.0	0.1	93.5	121.3	1795.2	3659.1
2428 MARTEN RIVER	2585.69	142823.0	229083.9	0.0	18.4	13554.2	17578.1	260197.7	672790.6
2429 THORNE	2665.00	16187.4	35675.9	0.0	2.9	2110.8	2737.5	40521.3	107989.4
2430 PLAYFAIR	2370.78	151.6	200.4	0.0	0.0	11.9	15.4	227.6	539.6
2431 LOWTHER	2123.86	538.1	819.6	0.0	0.1	48.5	62.9	930.9	1977.1
2432 VAL GAGNE	2339.13	43.3	63.3	0.0	0.0	3.7	4.9	71.9	168.2
TOTAL		575598.7	1013592.3	0.0	81.5	59971.0	77775.0	1151256.8	2865974.6

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS (a)	KMPOST (b)	DELIVERIES WINTER (c)	DELIVERIES TOTAL (d)	PS & TWS (e)	DIVERSION FROM (f)	DIVERSION TO (g)	OTHER (h)	FIRM SALES (i)	10^6m^3-KM (j)
NORTHERN ZONE (CONT'D)									
NORTHERN & CENT. - SSMDA 425									
2425 SAULT STE. MARIE	2168.80	189764.7	378302.0	0.0	0.0	0.0	0.0	378302.0	820461.4
2426 SOO AIRPORT	2160.67	267.6	367.2	0.0	0.0	0.0	0.0	367.2	793.4
TOTAL		190032.3	378669.2	0.0	0.0	0.0	0.0	378669.2	821254.8
TOTAL ZONE		765631.0	1392261.5	0.0	81.5	59971.0	77775.0	1529926.0	3687229.4
EASTERN ZONE									
NORTHERN & CENTRAL - CDA 517									
2505 BRACEBRIDGE	2802.80	2814.8	4335.1	0.0	0.2	1067.1	0.0	5402.0	15140.6
2506 GRAVENHURST	2815.65	4091.1	5691.7	0.0	0.3	1401.0	0.0	7092.4	19969.8
2507 ORILLIA	2852.27	26762.2	38955.4	0.0	2.2	9589.1	0.0	48542.3	138455.7
2508 HUNTSVILLE	2767.13	1225.5	8900.3	0.0	0.5	2190.9	0.0	11090.7	30689.3
2526 SOUTH RIVER	2705.43	538.7	1314.6	0.0	0.1	323.6	0.0	1638.1	4431.8
2527 MUSKOKA FALLS	2805.47	5274.8	10088.6	0.0	0.6	2483.4	0.0	12571.4	35268.7
2545 MADILL	2773.06	1962.0	3950.8	0.0	0.2	972.5	0.0	4923.1	13652.0
2549 BURK'S FALLS	2731.27	685.4	945.9	0.0	0.1	232.8	0.0	1178.7	3219.3
TOTAL		43354.5	74182.4	0.0	4.2	18260.4	0.0	92438.6	260827.2

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS (a)	KMPOST (b)	DELIVERIES WINTER (c)	DELIVERIES TOTAL (d)	PS & TWS (e)	DIVERSION FROM (f)	DIVERSION TO (g)	OTHER (h)	FIRM SALES (i)	10^6m^3-KM (j)
EASTERN ZONE (CONT'D)									
CONSUMERS' - CDA & SWDA 521									
2501 BRAMPTON	2977.51	60598.9	99724.0	0.0	7334.7	883.8	0.0	93273.1	277721.6
2502 RICHMOND HILL	2963.88	59098.7	89160.8	0.0	6557.8	790.2	0.0	83393.2	247167.4
2503 BOWMANVILLE	3031.82	88331.8	132710.1	0.0	9760.8	1176.1	0.0	124125.4	376325.9
2504 SHERIDAN	3005.62	-82.6	160769.3	0.0	11824.6	1424.8	0.0	150369.5	451953.7
2509 BARRIE	2887.69	128158.5	207936.5	0.0	15293.7	1842.8	0.0	194485.6	561614.1
2510 OSHAWA	3011.47	159793.0	246967.3	0.0	18164.5	2188.8	0.0	230991.6	695624.2
2514 GRIMSBY	3078.00	24379.3	35550.6	0.0	2614.7	315.1	0.0	33250.9	102346.3
2515 BLACK HORSE	3110.86	323127.1	598503.9	0.0	44020.0	5304.2	0.0	559788.1	1741422.6
2516 NIAGARA-ON-THE-LAKE	3126.95	13589.7	20294.6	0.0	1492.7	179.9	0.0	18981.8	59355.1
2518 VINELAND	3094.14	13571.8	19759.5	0.0	1453.5	175.1	0.0	18481.3	57183.7
2519 MOUNTAIN ROAD	3117.62	203770.1	313701.1	0.0	23072.7	2780.2	0.0	293408.5	914736.4
2520 PELHAM ROAD	3100.45	95527.3	152402.7	0.0	11209.2	1350.7	0.0	142544.1	441951.0
2521 MARKHAM	2978.19	320686.1	583977.9	0.0	42951.6	5175.5	0.0	546201.8	1626692.7
2523 BONDHEAD	2924.36	24347.6	35604.9	0.0	2618.7	315.5	0.0	33301.7	97386.2
2524 SCHOMBERG	2935.49	18652.2	26491.6	0.0	1948.5	234.8	0.0	24777.9	72735.3
2525 NOBLETON	2947.20	9565.2	12968.2	0.0	955.8	114.9	0.0	12129.3	35747.5
2534 VICTORIA SQUARE	2967.24	432118.5	1219365.8	0.0	89684.5	10806.6	0.0	1140488.0	3384101.6
2536 TRAFALGAR	2994.30	651.6	651.6	0.0	[illegible].9	5.8	0.0	609.4	1824.9
2539 BROOKLIN	3002.88	2515.5	3789.8	0.0	278.7	33.6	0.0	3544.6	10644.1
2542 LISGAR	2994.30	-544437.7	278397.8	0.0	20476.2	2467.3	0.0	260388.9	779682.6
2544 DAWN	2613.01	1219906.0	2688976.9	0.0	197774.5	23831.1	0.0	2515033.5	6571807.8
2546 VICTORIA SQUARE B	2967.24	252905.4	580028.6	0.0	42661.2	5140.5	0.0	542508.0	1609751.3
2548 COOKSTOWN	2912.89	325.9	702.1	0.0	51.6	6.2	0.0	656.7	1912.8
2574 LISGAR	2994.30	185892.3	185892.3	0.0	13672.4	1647.5	0.0	173867.4	520611.1
TOTAL		3092990.2	7694327.9	0.0	565918.4	68191.1	0.0	7196600.6	20640300.0

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS (a)	KMPOST (b)	DELIVERIES WINTER (c)	DELIVERIES TOTAL (d)	DIVERSION PS & TWS (e)	DIVERSION FROM (f)	DIVERSION TO (g)	OTHER (h)	FIRM SALES (i)	10^6m^3-KM (j)
EASTERN ZONE (CONT'D)									
UNION GAS 529									
2522 BURLINGTON	3026.42	120248.2	184284.4	0.0	0.0	0.0	0.0	184284.4	557722.0
2533 SARNIA	2592.61	698461.8	1522364.0	0.0	0.0	0.0	0.0	1522364.0	3946896.3
2543 DAWN	2613.01	604565.0	1800332.1	0.0	0.0	0.0	0.0	1800332.1	4704285.8
2547 SHERIDAN	3005.62	74240.1	121217.1	0.0	0.0	0.0	0.0	121217.1	364332.6
2554 HAMILTON GATE	3055.91	3040.4	230124.8	0.0	0.0	0.0	0.0	230124.8	703240.7
2576 DAWN-STS	2613.01	872.6	-73823.7	0.0	0.0	0.0	0.0	-73823.7	-192902.1
6503 LISGAR	2994.30	1087505.5	3108185.3	0.0	0.0	0.0	0.0	3108185.3	9306839.4
6576 LISGAR-STS	2994.30	251005.1	128212.7	0.0	0.0	0.0	0.0	128212.7	383907.3
TOTAL		2839938.7	7020896.7	0.0	0.0	0.0	0.0	7020896.7	19774321.9
CONSUMERS' - EDA 625									
2608 BROCKVILLE	3279.32	53715.3	107727.5	1078.8	6599.5	54769.7	0.0	154818.8	507700.4
2612 OTTAWA	3079.50	580484.7	878880.1	11658.8	53841.5	446831.0	0.0	1260210.8	3880819.3
2622 LANCASTER	3394.55	26884.1	48950.1	540.0	2998.8	24886.7	0.0	70298.1	238630.4
2626 LEEDS	3233.94	85.1	219.9	1.7	13.5	111.8	0.0	316.5	1023.6
2633 CAMPBELLFORD	3101.50	5752.0	10570.9	115.5	647.6	5374.3	0.0	15182.1	47087.4
2637 SUMMERSTOWN	3385.20	655.0	1647.1	13.2	100.9	837.4	0.0	2370.4	8024.4
2650 HALEY	2898.55	56965.5	64870.7	1144.1	3974.1	32980.9	0.0	92733.4	268792.3
2666 METCALFE	3375.32	1.1	249.1	0.0	15.3	126.6	0.0	360.5	1216.7
TOTAL		724542.8	1113115.4	14552.1	68191.1	565918.4	0.0	1596290.6	4953294.4

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS (a)	KMPOST (b)	DELIVERIES WINTER (c)	DELIVERIES TOTAL (d)	PS & TMS (e)	DIVERSION FROM (f)	DIVERSION TO (g)	OTHER (h)	FIRM SALES (i)	10^6m^3-KM (j)
EASTERN ZONE (CONT'D)									
NORTHERN & CENTRAL - EDA 637									
2601 PORT HOPE	3055.00	19380.1	30746.2	0.0	3408.9	0.0	755.8	28093.2	85824.6
2602 COBOURG	3065.70	23969.2	38505.2	0.0	4269.1	0.0	946.5	35182.6	107859.4
2603 TRENTON	3118.84	47366.7	84327.1	0.0	9349.4	0.0	2072.9	77050.6	240308.6
2604 BELLEVILLE	3132.47	30121.4	46934.8	0.0	5203.7	0.0	1153.8	42884.9	134335.6
2605 NAPANEE	3170.39	7949.4	12132.2	0.0	1345.1	0.0	298.2	11085.3	35144.8
2607 GANANOQUE	3237.40	7208.5	11061.5	0.0	1226.4	0.0	271.9	10107.0	32720.5
2609 PRESCOTT	3300.36	6776.0	9460.9	0.0	1048.9	0.0	232.6	8644.5	28530.1
2610 MORRISBURG	3334.19	2879.9	5051.1	0.0	560.0	0.0	124.2	4615.2	15388.1
2611 CORNWALL	3372.97	121644.7	236660.4	0.0	26238.7	0.0	5817.6	216239.3	729368.7
2614 COLBORNE	3089.11	1473.5	2785.4	0.0	308.8	0.0	68.5	2545.1	7861.9
2615 BRIGHTON	3112.59	144.7	313.4	0.0	34.7	0.0	7.7	286.4	891.3
2617 KINGSTON TWP.	3207.47	27.6	43.3	0.0	4.8	0.0	1.1	39.6	126.9
2618 CARDINAL	3313.83	14716.1	34110.0	0.0	3781.8	0.0	838.5	31166.7	103281.1
2619 IROQUOIS	3321.63	2492.5	4147.3	0.0	459.8	0.0	101.9	3789.4	12587.1
2620 AUGUSTA	3291.20	12372.2	115371.3	0.0	12791.3	0.0	2836.1	105416.1	346945.4
2623 PITTSBURGH TWP.	3219.33	1940.5	3070.8	0.0	340.5	0.0	75.5	2805.8	9032.9
2624 ERNESTOWN	3186.24	20607.6	69375.1	0.0	7691.7	0.0	1705.4	63388.8	201972.0
2625 WINCHESTER	3042.43	8030.3	16201.0	0.0	1796.2	0.0	398.3	14803.0	45037.2
2627 WESTBROOK	3197.38	39213.8	67853.4	0.0	7523.0	0.0	1668.0	61998.4	198232.5
2631 OSNABRUCK	3353.92	3422.8	7286.8	0.0	807.9	0.0	179.1	6658.0	22330.5
2632 THURLOW TWP.	3142.24	11872.2	16592.7	0.0	1839.6	0.0	407.9	15160.9	47639.3
2636 BARRIEFIELD	3209.43	11607.3	18348.6	0.0	2033.5	0.0	450.9	16758.9	53786.6
2639 MARYSVILLE	3157.10	4669.8	13474.4	0.0	1493.9	0.0	331.2	12311.7	38869.3
2640 STRATHCONA	3172.63	6278.4	15241.7	0.0	1689.9	0.0	374.7	13926.5	44183.7
2643 LONG SAULT	3364.14	1498.7	2230.8	0.0	247.3	0.0	54.8	2038.3	6857.2
2644 CORBYVILLE	3135.81	5301.0	8081.2	0.0	896.0	0.0	198.7	7383.9	23154.5
2662 MATTAWA	2707.66	67.9	135.3	0.0	15.0	0.0	3.3	123.6	334.7
TOTAL		413032.8	869534.9	0.0	96405.9	0.0	21375.0	794504.0	2572604.6
KINGSTON PUC 639									
2606 KINGSTON	3207.53	55443.7	91164.7	850.0	0.0	0.0	6000.0	96314.7	308932.3
					0.0	0.0	6000.0	96314.7	308932.3

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TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS	KMPOST	DELIVERIES		PS & TWS	DIVERSION		OTHER	FIRM SALES	10^6m^3-KM
		WINTER	TOTAL		FROM	TO			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
EASTERN ZONE (CONT'D)									
GAZ METROPOLITAIN 641									
2613 MONTREAL	3447.34	315791.1	447587.0	0.0	910.6	0.0	19666.8	466343.2	1607643.5
2634 ST. MATHIEU	3487.11	501163.5	973460.0	0.0	1980.5	0.0	42773.4	1014252.9	3536811.6
2636 VALLEYFIELD	3449.65	36822.3	66886.2	0.0	136.1	0.0	2939.0	69689.1	240402.9
2645 ST. JEAN	3506.88	14261.5	24934.6	0.0	50.7	0.0	1095.6	25979.5	91106.9
2646 BOISBRIAND	3478.47	814285.9	1510396.1	0.0	3072.9	0.0	66366.2	1573689.4	5474031.3
2655 VAUDREUIL	3448.37	902.2	1865.8	0.0	3.8	0.0	82.0	1944.0	6703.6
2659 BEAUHARNOIS	3455.95	588.0	4220.7	0.0	8.6	0.0	185.5	4397.6	15197.8
TOTAL		1683814.5	3029350.4	0.0	6163.2	0.0	133108.4	3156295.6	10971897.6
TRANS QUEBEC & MARITIMES 681									
2651 LOUISEVILLE	3592.87	3337.1	6389.8	0.0	0.0	239.3	0.0	6629.1	23817.4
2652 TROIS-RIVIERES	3627.47	31098.6	63101.1	0.0	0.0	2362.9	0.0	65464.0	237468.7
2653 ST. JEROME	3489.57	2744.6	5255.7	0.0	0.0	196.8	0.0	5452.5	19026.9
2654 JOLIETTE	3556.17	4408.2	7012.0	0.0	0.0	262.6	0.0	7274.6	25869.6
2656 ST. JANVIER	3486.57	3488.5	6606.4	0.0	0.0	247.4	0.0	6853.8	23896.2
2657 L' ASSOMPTION	3521.57	2422.3	4398.3	0.0	0.0	164.7	0.0	4563.0	16068.9
2658 QUEBEC OUEST	3731.27	23373.2	55164.4	0.0	0.0	2065.7	0.0	57230.1	213541.0
2660 BERTHIERVILLE	3563.97	2629.1	5980.2	0.0	0.0	223.9	0.0	6204.1	22111.4
2661 ST. MAURICE	3633.77	619.4	2253.1	0.0	0.0	84.4	0.0	2337.5	8493.8
2667 ST.ANNE DE LAPERADE	3665.07	0.0	2169.6	0.0	0.0	81.2	0.0	2250.8	8249.5
2668 PORTNEUF	3695.47	0.0	6010.8	0.0	0.0	225.1	0.0	6235.9	23044.5
2669 DONNACONA	3709.37	0.0	246.0	0.0	0.0	9.2	0.0	255.2	946.7
TOTAL		74121.0	164587.4	0.0	0.0	6163.2	0.0	170750.6	622534.6
TOTAL ZONE		8927238.2	20057159.8	15402.1	736682.8	658533.1	160483.4	20124091.4	60104712.6
TOTAL CANADIAN		11281520.1	23940643.6	44129.4	741533.0	741533.0	238258.4	24134772.6	66411318.1

TRANSCANADA PIPELINES

DETERMINATION OF VARIABLE ALLOCATION UNITS (10^3m^3)
12 MONTHS ENDED SEPTEMBER 30, 1984

PARTICULARS (a)	KMPOST (b)	DELIVERIES WINTER (c)	DELIVERIES TOTAL (d)	PS & TWS (e)	DIVERSION FROM (f)	DIVERSION TO (g)	OTHER (h)	FIRM SALES (i)	10^6m^3-KM (j)
EXPORT SALES									
INTER-CITY 201									
2225 SPRUCE	1002.25	78093.4	155353.8	0.0	0.0	0.0	0.0	155353.8	155703.3
TOTAL		78093.4	155353.8	0.0	0.0	0.0	0.0	155353.8	155703.3
MIDWESTERN 271									
2210 EMERSON	1023.39	1159707.2	1920582.7	0.0	0.0	0.0	0.0	1920582.7	1965504.9
2240 ANR PIPELINE CREDIT	1023.39	-215291.8	-485468.9	0.0	0.0	0.0	0.0	-485468.9	-496824.0
TOTAL		944415.4	1435113.8	0.0	0.0	0.0	0.0	1435113.8	1468681.0
GREAT LAKES 275									
2230 EMERSON	1023.39	5371021.6	11448245.2	0.0	0.0	0.0	0.0	11448245.2	11716018.4
2245 CONSOLIDATED CREDIT	1023.39	-438316.9	-830780.9	0.0	0.0	0.0	0.0	-830780.9	-850212.8
2248 PROGAS CREDIT	1023.39	-654233.5	-1604623.3	0.0	0.0	0.0	0.0	-1604623.3	-1642155.3
8230 EMERSON	1023.39	-3587812.8	-7386309.6	0.0	0.0	0.0	0.0	-7386309.6	-7559074.6
TOTAL		690658.4	1626531.4	0.0	0.0	0.0	0.0	1626531.4	1664575.8
ANR PIPELINE 281									
2242 EMERSON	1023.39	215291.8	485468.9	0.0	0.0	0.0	0.0	485468.9	496824.0
TOTAL		215291.8	485468.9	0.0	0.0	0.0	0.0	485468.9	496824.0
NIAGARA GAS 651									
2628 ST. LAWRENCE	3369.77	128800.7	226423.8	0.0	0.0	0.0	0.0	226423.8	762996.1
TOTAL		128800.7	226423.8	0.0	0.0	0.0	0.0	226423.8	762996.1
VERMONT GAS 661									
2630 PHILIPSBURG	3542.87	87002.4	141130.3	0.0	0.0	0.0	0.0	141130.3	500006.3
TOTAL		87002.4	141130.3	0.0	0.0	0.0	0.0	141130.3	500006.3
TOTAL EXPORT		2144262.1	4070022.0	0.0	0.0	0.0	0.0	4070022.0	5048786.5
TOTAL SYSTEM		13425782.2	28010665.6	44129.4	741533.0	741533.0	238258.4	28204794.6	71460104.7

TransCanada PipeLines Limited

Functional Distribution and Classification of Cost of Service

LINE NUMBER	PARTICULARS	TOTAL	COST OF GAS	MISCELLANEOUS TRANSMISSION	METERING	TRANSMISSION	
						FIXED	VARIABLE FUEL, USES & OTHER
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	COST OF GAS	3,149,419,718	3,149,419,718	0	0	0	0
2	TRANSMISSION BY OTHERS	187,365,566	0	270,500	0	145,131,586	41,963,480
3	OPERATION AND MAINTENANCE	338,170,891	0	0	6,912,908	126,914,050	204,343,933
4	DEPRECIATION	92,737,766	0	0	863,391	91,874,375	0
5	TAXES OTHER THAN INCOME	33,076,200	0	0	132,956	32,943,244	0
6	INCOME TAXES	126,734,000	0	0	1,169,006	125,564,994	0
7	REDUCTION IN DEFERRED INCOME TAXES	(23,000,000)	0	0	(23,000,000)	0	0
8	MISCELLANEOUS DEFERRED ITEMS	2,166,565	0	0	0	2,166,565	0
9	OTHER OPERATING INCOME	(5,434,536)	0	0	0	(78,120)	(5,356,416)
10	RETURN	385,138,903	0	0	3,552,556	381,586,347	0
11	SUMMER AOI FIXED	(50,823)	0	0	(50,823)	0	0
12	TOTAL COST OF SERVICE	4,286,324,250	3,149,419,718	270,500	(10,420,006)	906,103,041	240,950,997
13	MISCELLANEOUS REVENUE	(12,479,131)	(4,339,354)	(1,964)	(126,974)	(6,326,169)	(1,684,670)
14	NET COST OF SERVICE	4,273,845,119	3,145,080,364	268,536	(10,546,980)	899,776,872	239,266,327
15	NET COST OF TRANSMISSION (column (b) - column (c))	1,128,764,755					

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TransCanada PipeLines Limited

DISTRIBUTION OF COST OF TRANSMISSION

PARTICULARS	COST ALLOCATION UNITS				ALLOCATED TRANSMISSION COST		
	FIXED (10^3m^3)	VARIABLE (10^3m^3)	FIXED (10^3m^3-km)	VARIABLE (10^3m^3-km)	FIXED ($)	VARIABLE ($)	TOTAL ($)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
SULPETRO							
TRANSPORTATION SERVICE	2125	660000	6552994	2038272200			
COST OF METERING					232796	0	232796
COST OF TRANSMISSION-FUEL, USES & OTHER					0	6085384	6085384
COST OF TRANSMISSION-FIXED					23957424	0	23957424
COST OF TRANSMISSION-MISC					0	0	0
TOTAL					24190221	6085384	30275604
TOTAL	2125	660000	6552994	2038272200	24190221	6085384	30275604
SYSTEM SALES SERVICE	95229	30078400	212947557	72245311900	792351809	216836512	1009188321
SYSTEM T SERVICE	3146	983000	9634136	2976627300	32173029	8011630	40184659
SYSTEM TRANSPORTATION SERVICE	15762	4013000	17226245	4919252400	64705052	14686723	79391774
TOTAL SYSTEM SERVICE	114137	35074400	239807938	80141191600	889229890	239534865	1128764755

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TransCanada PipeLines Limited

DISTRIBUTION OF COST OF TRANSMISSION

PARTICULARS	FUNCTIONALIZED COST OF TRANSMISSION FIXED ($)	VARIABLE ($)	TOTAL ($)	ALLOCATION BASE FIXED	VARIABLE	UNIT COST FIXED	VARIABLE
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
COST OF METERING	12503843	0	12503843	114137	0	109.5511797226	0.0000000000
COST OF TRANSMISSION-FUEL, USES AND OTHER	0	239266328	239266328	0	80141191600	0.0000000000	0.0029855599
COST OF TRANSMISSION-FIXED	876726047	0	876726047	239807938	80141191600	3.6559509010	0.0000000000
COST OF TRANSMISSION-MISC	0	268536	268536	0	31061400	0.0000000000	0.0086453283
TOTAL	889229890	239534865	1128764755				

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PROPOSED

TransCanada PipeLines Limited

Toll Differential between CD Service and ACQ Service

The calculation of the toll differential is based on the costs of storage service, inventories and transportation service needed to provide CD Service instead of ACQ Service.

To provide CD Service instead of ACQ Service, the following would be required.

(A) The additional amount of transportation service which would be required by TransCanada on Union's system would be a daily demand volume of 14.6 10^6m^3 and a corresponding annual volume of 2 205 10^6m^3. This assumes that Consumers' and Union would take delivery of the CD Service at Oakville; whereas, under the ACQ Service, TransCanada has the option of delivering the volumes at Dawn.

(B) The storage service which would be required could be obtained using Union's storage facilities.

The daily deliverability required from storage would be 7.5 10^6m^3, which is the difference between the Contract Demand level of 14.6 10^6m^3 under CD Service and the "firm daily" ACQ Service level of 7.1 10^6m^3.

The storage capacity required would be 1 113 10^6m^3. This is the volume required to permit a daily injection demand of 5.564 10^6m^3 in light of the requirement that such demand not exceed 0.5% of the contracted storage space. The daily injection demand volume is the difference between the maximum daily ACQ summer volume and the daily equivalent of 5 323 10^6m^3 for 365 days.

The seasonal deliverability required would be 76 10^6m^3 which is the difference between the winter season deliveries under CD Service and those under ACQ Service.

If TransCanada were to contract for storage service to supply CD Service, then injection and withdrawal volumes of 296 10^6m^3 would be encountered in order to cover the day-to-day variations in ACQ deliveries to Union. A further 532 10^6m^3 would be required to cover hourly variations.

TransCanada PipeLines Limited

Toll Differential between CD Service and ACQ Service

(C) The difference in winter season deliveries of 76 10^6m^3 is assumed to be stored for half a year.

For protection against seasonal or annual reductions which may occur under ACQ Service but not under CD Service, 5% of the annual ACQ volume and 10% of the winter season ACQ volume would be kept in inventory. The sum of these two volumes or 479 10^6m^3 is assumed to be stored for a whole year.

TransCanada Pipelines Limited

Toll Differential Between CD Service and ACQ Service

Line No.	A. Cost of Transportation Service		Rate		Volume (10⁶m³)	Cost ($000)
1	Demand (1) ($/10³m³/mo.)		47.199		14.6	8,269
2	Commodity ($/10³m³)	(TCPL) (2)	1.519		1,254	1,905
3		(Others) (3)	1.692		951	1,609
4	Total Cost of Transportation					11,783

	B. Cost of Storage Service		Rate	Volume (10⁶m³)	($000)	
5	Demand Charge (4) ($/10³m³/mo.)		29.646	7.5	2,668	
6	Space Charge (5) ($/10³m³/mo.)		0.458	1,113	6,117	
7	Injection and Withdrawal Charge (6) ($/10³m³)	-season	1.728	76	131	
8		-daily	1.728	296	511	
9		-hourly	1.728	532	919	
10	Total Cost of Storage					10,346

	C. Cost of Inventory	Rate $	Volume (10⁶m³)	Cost (CB-$/10³m³)	
11	Six Months' Inventory (7)	7.570	76	145.990	840
12	Twelve Months' Inventory (7)	15.140	479	145.990	10,587
13	Total Cost of Inventory				11,427
14	Total				33,556
15	Average Cost on 5,323.0 10⁶m³				6.304
16	Recommended for Toll Differential			$6.3	/10³m³

TransCanada PipeLines Limited

Toll Differential between CD Service and ACQ Service

Notes

1. The demand charge was taken from OEB order EBRO 397 approving Union's Rate #12 effective April 24, 1984. The volume is the daily equivalent of 5 323 10^6m^3 for 365 days.

2. The commodity charge is Union Gas' commodity rate for "TCPL". The volume transported is for ultimate sale to Union and is Union's portion of the winter volume of 2 205 10^6m^3, determined based on an annual ACQ split of 3 028 10^6m^3 for Union and 2 295 10^6m^3 for Consumers'.

3. The commodity charge is Union Gas' commodity rate for "Others". The volume that would be transported is for ultimate sale to Consumers' and is Consumers' portion of the winter volume of 2 205 10^6m^3, determined based on the same annual split as in Note 2 above.

4. The storage demand charges are taken from OEB order EBRO 397 approving Union's Rate #12 effective April 24, 1984. The demand volume is the difference between the volume under CD Service and the "firm daily" volume under ACQ Service.

5. The storage space charges are taken from OEB order EBRO 397 approving Union's Rate #12 effective April 24, 1984. The volume represents the storage capacity required to permit a daily injection demand of 5.564 10^6m^3 in light of the requirement that such demand not exceed 0.5% of the contracted storage space. The daily injection demand volume is the difference between the maximum daily ACQ summer volume (135% of the average summer day) and the daily equivalent of 5 323 10^6m^3 for 365 days.

TransCanada PipeLines Limited

Toll Differential between CD Service and ACQ Service

Notes (Continued)

6. The storage injection and withdrawal charges are taken from OEB order EBRO 397 approving Union's Rate #12 effective April 24, 1984.

   Seasonal Volume - This volume is the difference between winter season deliveries under CD Service and winter season deliveries under ACQ Service.

   Daily Volume - This volume reflects the day-to-day variations in ACQ deliveries to Union from TransCanada for the 1983-1984 contract year. If TransCanada were to have contracted for storage service to cover these variations in order to supply CD Service rather than ACQ Service then injection and withdrawal volumes of 296 10^6m^3 would have been encountered.

   Hourly Volume - This volume is 10% of 5 323 10^6m^3.

7. The difference in winter season deliveries of 76 10^6m^3 under CD Service versus ACQ Service is assumed to be stored for half a year.

   For protection against seasonal or annual reductions which may occur under ACQ Service but not under CD Service, 5% of the annual ACQ volume must be kept in inventory as well as 10% of the winter season ACQ volume. The sum of these volumes, or 479 10^6m^3, is assumed to be stored for a whole year.

Table 1

TransCanada PipeLines

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1

(Volumes at 101.325 kPa)

LINE		1986		1987		1988		1990		1995	
		Winter Maximum Daily Demand (10^3m^3)	Annual Delivery (10^6m^3)	Winter Maximum Daily Demand (10^3m^3)	Annual Delivery (10^6m^3)	Winter Maximum Daily Demand (10^3m^3)	Annual Delivery (10^6m^3)	Winter Maximum Daily Demand (10^3m^3)	Annual Delivery (10^6m^3)	Winter Maximum Daily Demand (10^3m^3)	Annual Delivery (10^6m^3)
	SALES										
1	Canadian (See Table 2)	70 974	24 445	72 654	24 838	73 441	25 294	73 801	25 381	73 801	25 381
	Export										
2	Existing	23 501	7 513	23 871	7 795	24 161	8 054	10 593	3 449	1 730	548
3	New	4 036	1 756	8 570	3 128	12 534	4 575	12 534	4 575	9 627	3 514
4	Total Export (See Table 3)	27 537	9 269	32 441	10 923	36 695	12 629	23 127	8 024	11 357	4 062
5	TOTAL SALES	98 571	33 714	105 095	35 761	110 136	37 923	96 928	33 405	85 158	29 443
6	Company Fuel, Losses & Other Uses		2 232		2 663		3 018		1 996		1 540
7	TOTAL MAINLINE REQUIREMENTS		35 946		38 424		40 941		35 401		30 983
	TRANSPORTATION										
8	Canadian	12 014	2 018	12 139	2 038	12 239	2 058	12 239	2 068	12 239	2 068
	Export										
9	Existing	9 562	2 795	7 862	2 393	6 162	1 877	2 125	435	-	-
10	New	2 635	963	11 253	2 752	20 170	4 681	19 660	4 526	16 057	3 935
11	Total Export	12 197	3 758	19 115	5 145	26 332	6 558	21 785	4 961	16 057	3 935
12	TOTAL TRANSPORTATION (See Table 4)	24 211	5 776	31 254	7 183	38 571	8 616	34 024	7 029	28 296	6 003
13	TOTAL REQUIREMENTS		41 722		45 607		49 557		42 430		36 986

S.F. No. 84-513

TransCanada PipeLines

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1

(Volumes at 101.325 kPa)

LINE		Class of Service	1986 Winter Maximum Daily Demand (10^3m^3)	1986 Annual Delivery (10^6m^3)	1987 Winter Maximum Daily Demand (10^3m^3)	1987 Annual Delivery (10^6m^3)	1988 Winter Maximum Daily Demand (10^3m^3)	1988 Annual Delivery (10^6m^3)	1990 Winter Maximum Daily Demand (10^3m^3)	1990 Annual Delivery (10^6m^3)	1995 Winter Maximum Daily Demand (10^3m^3)	1995 Annual Delivery (10^6m^3)
	Saskatchewan Power Corporation											
1	Southern Delivery Area	CD	285	42	285	42	285	42	285	42	285	42
	Inter-City Gas Limited											
2	Manitoba Delivery Area	CD	871	220	871	220	871	220	871	220	871	220
3	Saskatchewan Southern Delivery Area	CD	225	30	225	30	225	30	225	30	225	30
4	Total Inter-City		1 096	250	1 096	250	1 096	250	1 096	250	1 096	250
5	Greater Winnipeg Gas Limited	CD	7 170	1 352	7 170	1 352	7 170	1 352	7 170	1 352	7 170	1 352
6		PS	425	1	425	1	425	1	425	1	425	1
7		TWS	(340)	17	(340)	17	(340)	17	(340)	17	(340)	17
8		Total	7 595	1 370	7 595	1 370	7 595	1 370	7 595	1 370	7 595	1 370
9	Plains-Western Gas (Manitoba) Limited	CD	1 164	335	1 164	335	1 164	335	1 164	335	1 164	335
10	Northern & Central Gas Corporation Ltd.											
11	Western Zone	CD	2 490	680	2 490	680	2 490	680	2 490	680	2 490	680
12	Northern Delivery Area	CD	3 885	1 140	3 885	1 140	3 885	1 140	3 885	1 140	3 885	1 140
13		TWS	(360)	24	(360)	24	(360)	24	(360)	24	(360)	24
14		Total	3 885	1 164	3 885	1 164	3 885	1 164	3 885	1 164	3 885	1 164
15	Sault Ste. Marie Delivery Area	CD	1 490	407	1 490	407	1 490	407	1 490	407	1 490	407
16		PS	140	1	140	1	140	1	140	1	140	1
17		TWS	(30)	2	(30)	2	(30)	2	(30)	2	(30)	2
18		Total	1 630	410	1 630	410	1 630	410	1 630	410	1 630	410
19	Central Delivery Area	CD	290	106	290	106	290	106	290	106	290	106
20		PS	85	1	85	1	85	1	85	1	85	1
21		Total	375	107	375	107	375	107	375	107	375	107

TransCanada PipeLines

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1

(Volumes at 101.325 kPa)

LINE		Class of Service	1986 Winter Maximum Daily Demand (10^3m^3)	1986 Annual Delivery (10^6m^3)	1987 Winter Maximum Daily Demand (10^3m^3)	1987 Annual Delivery (10^6m^3)	1988 Winter Maximum Daily Demand (10^3m^3)	1988 Annual Delivery (10^6m^3)	1990 Winter Maximum Daily Demand (10^3m^3)	1990 Annual Delivery (10^6m^3)	1995 Winter Maximum Daily Demand (10^3m^3)	1995 Annual Delivery (10^6m^3)
	Northern & Central Gas Corp. Ltd.											
1	Eastern Delivery Area	CD	2 065	754	2 065	754	2 065	754	2 065	754	2 065	754
2		PS	85	1	85	1	85	1	85	1	85	1
3		TWS	(85)	9	(85)	9	(85)	9	(85)	9	(85)	9
4		Total	2 150	764	2 150	764	2 150	764	2 150	764	2 150	764
5	Total Northern,& Central		10 530	3 125	10 530	3 125	10 530	3 125	10 530	3 125	10 530	3 125
	The Consumers' Gas Company											
6	Central/Southwestern Delivery Area	CD	12 505	4 564	12 505	4 564	12 505	4 564	12 505	4 564	12 505	4 564
7		ACQ	3 040	2 520	3 377	2 550	3 377	2 550	3 377	2 550	3 377	2 550
8		PS	1 700	17	1 700	17	1 700	17	1 700	17	1 700	17
9		Total	17 245	7 101	17 582	7 131	17 582	7 131	17 582	7 131	17 582	7 131
10	Eastern Delivery Area	CD	4 485	1 516	4 485	1 536	4 485	1 606	4 485	1 606	4 485	1 606
11		PS	2 300	23	2 300	23	2 300	23	2 300	23	2 300	23
12		Total	6 785	1 539	6 785	1 559	6 785	1 629	6 785	1 629	6 785	1 629
	Total Consumers' Gas		24 030	8 640	24 367	8 690	24 367	8 760	24 367	8 760	24 367	8 760
13	Union Gas Limited	CD	10 100	3 687	10 100	3 687	10 100	3 690	10 100	3 690	10 100	3 690
14		ACQ	4 010	3 238	4 453	3 365	4 830	3 650	4 830	3 650	4 830	3 650
15		Total	14 110	6 925	14 553	7 052	14 930	7 340	14 930	7 340	14 930	7 340
16	Kingston Public Utilities Commission	CD	209	68	209	69	209	70	209	71	209	71
17		PS	85	1	85	1	85	1	85	1	85	1
18		Total	294	69	294	70	294	71	294	72	294	72
19	Gaz Metropolitain, Inc.	CD	9 176	3 050	9 176	3 050	9 176	3 050	9 176	3 050	9 176	3 050
20	Trans Quebec & Maritimes Pipelines Inc.	CD	2 694	639	3 594	854	4 004	951	4 364	1 037	4 364	1 037
21	Total Canadian Sales		70 974	24 445	72 654	24 838	73 441	25 294	73 801	25 381	73 801	25 381

TransCanada PipeLines

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1

(Volumes at 101.325 kPa)

LINE		Licence	Class of Service	1986 Winter Maximum Daily Demand (10^3m^3)	1986 Annual Delivery (10^6m^3)	1987 Winter Maximum Daily Demand (10^3m^3)	1987 Annual Delivery (10^6m^3)	1988 Winter Maximum Daily Demand (10^3m^3)	1988 Annual Delivery (10^6m^3)	1990 Winter Maximum Daily Demand (10^3m^3)	1990 Annual Delivery (10^6m^3)	1995 Winter Maximum Daily Demand (10^3m^3)	1995 Annual Delivery (10^6m^3)
	Existing Exports												
1	Midwestern Gas Trans. Co.	GL-60,89	CD	5 194	1 973	5 194	2 096	5 194	2 096	4 207	1 396	-	-
2		GL-18	CD	4 278	1 171	4 278	1 178	4 278	1 178	-	-	-	-
3		GL-39	CD	204	56	204	56	204	56	-	-	-	-
4		Total		9 676	3 200	9 676	3 330	9 676	3 330	4 207	1 396	-	-
5	Great Lakes Gas Trans. Co.	GL-20	CD	2 663	972	2 663	972	2 663	972	2 663	972	-	-
6		GL-37	CD	5 547	2 025	5 547	2 025	5 547	2 025	-	-	-	-
7		GL-43	CD	1 714	239	2 084	384	2 374	631	2 299	728	1 730	548
8		Total		9 924	3 236	10 294	3 381	10 584	3 628	4 962	1 700	1 730	548
9	American Natural Resources	GL-38	CD	1 416	517	1 416	517	1 416	517	-	-	-	-
10	Inter-City Gas Limited	GL-28,29	CD	625	170	625	170	625	170	625	170	-	-
11	Niagara Gas Trans. Co.	GL-55,78	CD	1 135	236	1 135	241	1 135	250	799	183	-	-
12	Vermont Gas Systems, Inc.	GL-19	CD	725	154	725	156	725	159	-	-	-	-
13	TOTAL EXISTING EXPORTS			23 501	7 513	23 871	7 795	24 161	8 054	10 593	3 449	1 730	548
	New Exports												
14	Natural Gas Pipeline Co.	GL-86	CD	1 416	517	-	-	-	-	-	-	-	-
15	TransContinental Gas Pipeline	GL-88	CD	-*	283	2 550	931	4 249	1 551	4 249	1 551	3 187	1 163
16	Tennessee Gas Pipeline Co.	GL-84,85	CD	-	-	2 550	931	4 249	1 551	4 249	1 551	4 249	1 551
17	Boundary Gas Inc.	GL-83	CD	2 620	956	2 620	956	2 620	956	2 620	956	775	283
18	Texas Eastern Trans. Corp.	GL-90	CD	-	-	850	310	1 416	517	1 416	517	1 416	517
19	TOTAL NEW EXPORTS			4 036	1 756	8 570	3 128	12 534	4 575	12 534	4 575	9 627	3 514
20	TOTAL EXPORT SALES			27 537	9 269	32 441	10 923	36 695	12 629	23 127	8 024	11 357	4 062

TransCanada Pipelines

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1

(Volumes at 101.325 kPa)

LINE		Licence	Class of Service	1986 Winter Maximum Daily Demand (10^3m^3)	1986 Annual Delivery (10^6m^3)	1987 Winter Maximum Daily Demand (10^3m^3)	1987 Annual Delivery (10^6m^3)	1988 Winter Maximum Daily Demand (10^3m^3)	1988 Annual Delivery (10^6m^3)	1990 Winter Maximum Daily Demand (10^3m^3)	1990 Annual Delivery (10^6m^3)	1995 Winter Maximum Daily Demand (10^3m^3)	1995 Annual Delivery (10^6m^3)
	TRANSPORTATION												
	Canadian												
1	Saskatchewan Power Corporation		TS	4 110	770	4 110	770	4 110	770	4 110	770	4 110	770
2	Plains-Western Gas Co.		TS	285	85	285	85	285	85	285	85	285	85
3	Northern & Central Gas Corp. Ltd.		STS	1 620	99	1 620	99	1 620	99	1 620	99	1 620	99
4	Kingston Public Utilities Comm.		STS	65	7	65	7	65	7	65	7	65	7
5	Gaz Inter-Cite Quebec		TS	1 475	300	1 600	320	1 700	340	1 700	350	1 700	350
6	Gaz Metropolitain, Inc.		TS	1 006	567	1 006	567	1 006	567	1 006	367	1 006	367
7			STS	2 520	170	2 520	170	2 520	170	2 520	170	2 520	170
8	Gaz Metropolitain, Inc.	]: Total		3 526	537	3 526	537	3 526	537	3 526	537	3 526	537
9	Trans Quebec & Maritimes Pipelines		TS	933	220	933	220	933	220	933	220	933	220
10	TOTAL CANADIAN			12 014	2 018	12 139	2 038	12 239	2 058	12 239	2 068	12 239	2 068
	Existing Exports												
11	Consolidated Natural Gas Limited	GL-44,61,75	TS	3 612	910	3 612	970	3 612	970	1 700	280	-	-
12	Progas Limited	GL-56,79	TS	3 825	1 225	2 550	865	1 275	465	-	-	-	-
13	Sulpetro Limited	GL-82	TS	2 125	660	1 700	558	1 275	442	425	155	-	-
14	Total Existing Exports			9 562	2 795	7 862	2 393	6 162	1 877	2 125	435	-	-
	New Exports												
15	Progas Limited	GL-81	TS	2 635	963	-	-	-	-	-	-	-	-
16	Progas Limited	GL-80	TS	-	-	851	311	1 420	518	1 420	518	1 420	518
17	Canadian-Montana Pipe Line Co.	GL-5,17,25,70,71	TS	-	-	1 428	434	2 380	724	1 870	569	391	119
18	Pan-Alberta Gas Limited	GL-95	TS	-	-	2 600	949	4 332	1 581	4 332	1 581	4 332	1 581
19	KennGas Producers Limited	GL-77	TS	-	-	2 125	775	3 540	1 292	3 540	1 292	3 540	1 292
20	TransContinental Gas Pipe Line	GL-91	STS	-	-	4 249	283	8 498	566	8 498	566	6 374	425
21	TOTAL NEW EXPORTS			2 635	963	11 253	2 752	20 170	4 681	19 660	4 526	16 057	3 935
22	TOTAL EXPORT TRANSPORTATION			12 197	3 758	19 115	5 145	26 332	6 558	21 785	4 961	16 057	3 935
23	TOTAL TRANSPORTATION			24 211	5 776	31 254	7 183	38 571	8 616	34 024	7 029	28 296	6 003
	SUMMARY - Class of Service												
24	Transportation Service		TS	20 006	5 500	22 800	6 624	25 868	7 774	21 521	6 187	17 717	5 302
25	Storage Transportation Service		STS	4 205	276	8 454	559	12 703	842	12 703	842	10 579	701
26	TOTAL TRANSPORTATION (Line 23)			24 211	5 776	31 254	7 183	38 571	8 616	34 024	7 029	28 296	6 003

TransCanada PipeLines Limited

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1, 1985 TO 1992

($10^6 m^3$ at 101.325 kPa)

LINE		1985	1986	1987	1988	1989	1990	1991	1992
	Canadian Sales								
1	Saskatchewan Power Corporation Limited	42	42	42	42	42	42	42	42
2	Inter-City Gas Limited	250	250	250	250	250	250	250	250
3	Greater Winnipeg Gas Limited	1 370	1 370	1 370	1 370	1 370	1 370	1 370	1 370
4	Plains-Western (Manitoba) Limited	335	335	335	335	335	335	335	335
5	Northern & Central Gas Corporation Limited	3 075	3 125	3 125	3 125	3 125	3 125	3 125	3 125
6	The Consumers' Gas Company Limited	8 523	8 640	8 690	8 760	8 760	8 760	8 760	8 760
7	Union Gas Limited	6 925	6 925	7 052	7 340	7 340	7 340	7 340	7 340
8	Kingston Public Utilities Commission	68	69	70	71	72	72	72	72
9	Gaz Metropolitain, Inc.	3 050	3 050	3 050	3 050	3 050	3 050	3 050	3 050
10	Trans Quebec & Maritimes Pipeline Inc.	403	639	854	951	1 037	1 037	1 037	1 037
11	TOTAL CANADIAN SALES	24 041	24 445	24 838	25 294	25 381	25 381	25 381	25 381
12	TOTAL EXPORT SALES (See Table 6)	8 241	9 269	10 923	12 629	11 294	8 024	6 171	5 361
13	TOTAL SALES	32 282	33 714	35 761	37 923	36 675	33 405	31 552	30 742
14	Company Fuel, Losses & Uses	2 098	2 232	2 663	3 018	2 430	1 996	1 794	1 735
15	TOTAL MAINLINE REQUIREMENTS	34 380	35 946	38 424	40 941	39 105	35 401	33 346	32 477
16	TOTAL TRANSPORTATION (See Table 7)	5 976	5 776	7 183	8 616	7 302	7 029	6 874	6 492
17	TOTAL REQUIREMENTS	40 356	41 722	45 607	49 557	46 407	42 430	40 220	38 969

S.F. #84-513

TransCanada PipeLines Limited

ESTIMATED REQUIREMENTS
YEARS COMMENCING NOVEMBER 1, 1993 TO 1999

($10^6 m^3$ at 101.325 kPa)

LINE		1993	1994	1995	1996	1997	1998	1999
	Canadian Sales							
1	Saskatchewan Power Corporation Limited	42	42	42	42	42	42	42
2	Inter-City Gas Limited	250	250	250	250	250	250	250
3	Greater Winnipeg Gas Limited	1 370	1 370	1 370	1 370	1 370	1 370	1 370
4	Plains-Western (Manitoba) Limited	335	335	335	335	335	335	335
5	Northern & Central Gas Corporation Limited	3 125	3 125	3 125	3 125	3 125	3 125	3 125
6	The Consumers' Gas Company Limited	8 760	8 760	8 760	8 760	8 760	8 760	8 760
7	Union Gas Limited	7 340	7 340	7 340	7 340	7 340	7 340	7 340
8	Kingston Public Utilities Commission	72	72	72	72	72	72	72
9	Gaz Metropolitain, Inc.	3 050	3 050	3 050	3 050	3 050	3 050	3 050
10	Trans Quebec & Maritimes Pipeline Inc.	1 037	1 037	1 037	1 037	1 037	1 037	1 037
11	TOTAL CANADIAN SALES	25 381	25 381	25 381	25 381	25 381	25 381	25 381
12	TOTAL EXPORT SALES (See Table 6)	5 357	4 931	4 062	2 797	1 005	433	269
13	TOTAL SALES	30 738	30 312	29 443	28 178	26 386	25 814	25 650
14	Company Fuel, Losses & Uses	1 697	1 670	1 540	1 268	970	783	653
15	TOTAL MAINLINE REQUIREMENTS	32 435	31 982	30 983	29 446	27 356	26 597	26 303
16	TOTAL TRANSPORTATION (See Table 7)	6 403	6 243	6 003	4 895	3 907	2 915	2 068
17	TOTAL REQUIREMENTS	38 838	38 225	36 986	34 341	31 263	29 512	28 371

TransCanada Pipelines Limited

ESTIMATED EXPORT SALES
YEARS COMMENCING NOVEMBER 1, 1985 TO 1992

($10^6 m^3$ at 101.325 kPa)

LINE		Port of Exit	Licence	1985	1986	1987	1988	1989	1990	1991	1992
	Existing Exports										
1	Midwestern Gas Transmission Co.	Emerson	GL-18,39,60,89	3 070	3 200	3 330	3 330	2 171	1 396	698	-
2	Great Lakes Gas Transmission Co.	Emerson	GL-20,37,43	3 178	3 236	3 381	3 628	3 606	1 700	636	616
3	American Natural Resources	Emerson	GL-38	517	517	517	517	517	-	-	-
4	Inter-City Gas Ltd.	Spruce	GL-28,29	170	170	170	170	170	170	170	170
5	Niagara Gas Transmission Ltd.	Cornwall	GL-55,78	224	236	241	250	255	183	92	-
6	Vermont Gas Systems, Inc.	Phillipsburg	GL-19	151	154	156	159	-	-	-	-
7	TOTAL EXISTING EXPORTS			7 310	7 513	7 795	8 054	6 719	3 449	1 596	786
	New Exports										
8	Natural Gas Pipeline Co.	Emerson	GL-86	517	517	-	-	-	-	-	-
9	TransContinental Gas Pipeline Corp.	Emerson	GL-88	-	283	566	566	566	566	566	566
10	Transcontinental Gas Pipeline Corp.	Niagara	GL-88	-	-	365	985	985	985	985	985
11	Tennessee Gas Pipeline Co.	Niagara	GL-84,85	-	-	931	1 551	1 551	1 551	1 551	1 551
12	Boundary Gas Inc.	Niagara	GL-83	414	956	956	956	956	956	956	956
13	Texas Eastern Transmission Corp.	Niagara	GL-90	-	-	310	517	517	517	517	517
14	TOTAL NEW EXPORTS			931	1 756	3 128	4 575	4 575	4 575	4 575	4 575
15	TOTAL EXPORT SALES			8 241	9 269	10 923	12 629	11 294	8 024	6 171	5 361

TransCanada PipeLines Limited

ESTIMATED EXPORT SALES
YEARS COMMENCING NOVEMBER 1, 1993 TO 1999

($10^6 m^3$ at 101.325 kPa)

LINE		Port of Exit	Licence	1993	1994	1995	1996	1997	1998	1999
	Existing Exports									
1	Midwestern Gas Transmission Co.	Emerson		-	-	-	-	-	-	-
2	Great Lakes Gas Transmission Co.	Emerson	GL-43	612	587	548	471	359	304	269
3	American Natural Resources	Emerson		-	-	-	-	-	-	-
4	Inter-City Gas Ltd.	Spruce	GL-28,29	170	170	-	-	-	-	-
5	Niagara Gas Transmission Ltd.	Cornwall		-	-	-	-	-	-	-
6	Vermont Gas Systems, Inc.	Phillipsburg		-	-	-	-	-	-	-
7	TOTAL EXISTING EXPORTS			782	757	548	471	359	304	269
	New Exports									
8	Natural Gas Pipeline Co.	Emerson	GL-86	-	-	-	-	-	-	-
9	TransContinental Gas Pipeline Corp.	Emerson	GL-88	566	566	425	283	142	-	-
10	TransContinental Gas Pipeline Corp.	Niagara	GL-88	985	985	738	492	246	-	-
11	Tennessee Gas Pipeline Co.	Niagara	GL-84,85	1 551	1 551	1 551	1 163	-	-	-
12	Boundary Gas Inc.	Niagara	GL-83	956	555	283	-	-	-	-
13	Texas Eastern Transmission Corp.	Niagara	GL-90	517	517	517	388	258	129	-
14	TOTAL NEW EXPORTS			4 575	4 174	3 514	2 326	646	129	-
15	TOTAL EXPORT SALES			5 357	4 931	4 062	2 797	1 005	433	269

TransCanada PipeLines Limited

ESTIMATED TRANSPORTATION SERVICES
YEARS COMMENCING NOVEMBER 1, 1985 TO 1992

($10^6 m^3$ at 101.325 kPa)

LINE		Point of Exit	Licence	Class of Service	1985	1986	1987	1988	1989	1990	1991	1992
1	Saskatchewan Power Corporation			TS	760	770	770	770	770	770	770	770
2	Plains-Western (Manitoba) Ltd.			TS	85	85	85	85	85	85	85	85
3	Northern & Central Gas Corporation Limited			STS	99	99	99	99	99	99	99	99
4	Kingston Public Utilities Commission			STS	7	7	7	7	7	7	7	7
5	Gaz Inter-Cite Quebec			TS	270	500	320	340	350	350	350	350
6	Gaz Metropolitain, Inc.			TS	367	367	367	367	367	367	367	367
7				STS	170	170	170	170	170	170	170	170
8	Gaz Metropolitain, Inc.			Total	537	537	537	537	537	537	537	537
9	TransQuebec & Maritimes Pipeline Inc.			TS	220	220	220	220	220	220	220	220
10	TOTAL CANADIAN				1 978	2 018	2 038	2 058	2 068	2 068	2 068	2 068
	Existing Exports											
11	Consolidated Natural Gas Limited	Emerson	GL-44,61,75	TS	865	910	970	970	280	280	280	-
12	Progas Limited	Emerson	GL-56,79	TS	1 550	1 225	865	465	-	-	-	-
13	Sulpetro Limited	Niagara	GL-82	TS	620	660	558	442	312	155	-	-
14	TOTAL EXISTING EXPORTS				3 035	2 795	2 393	1 877	592	435	280	-
	New Exports											
15	ProGas Limited	Emerson	GL-81	TS	963	963	-	-	-	-	-	-
16	ProGas Limited	Niagara	GL-80	TS	-	-	311	518	518	518	518	518
17	Canadian-Montana Pipe Line Company	Niagara	GL-5,17,25,70,71	TS	-	-	434	724	685	569	569	467
18	Pan Alberta Gas Limited	Niagara	GL-95	TS	-	-	949	1 581	1 581	1 581	1 581	1 581
19	KannGaz Producers Limited	Niagara	GL-77	TS	-	-	775	1 292	1 292	1 292	1 292	1 292
20	Transcontinental Gas Pipe Line Corp.	Niagara	GL-91	STS	-	-	283	566	566	566	566	566
21	TOTAL NEW EXPORTS				963	963	2 752	4 681	4 642	4 526	4 526	4 424
22	TOTAL EXPORT TRANSPORTATION				3 998	3 758	5 145	6 558	5 234	4 961	4 806	4 424
23	TOTAL TRANSPORTATION				5 976	5 776	7 183	8 616	7 502	7 029	6 874	6 492
	SUMMARY - Class of Service											
24	Transportation Service			TS	5 700	5 500	6 624	7 774	6 460	6 187	6 032	5 650
25	Storage Transportation Service			STS	276	276	559	842	842	842	842	842
26	TOTAL TRANSPORTATION (Line 23)			Total	5 976	5 776	7 183	8 616	7 502	7 029	6 874	6 492

S.F. #84-513

TransCanada PipeLines Limited

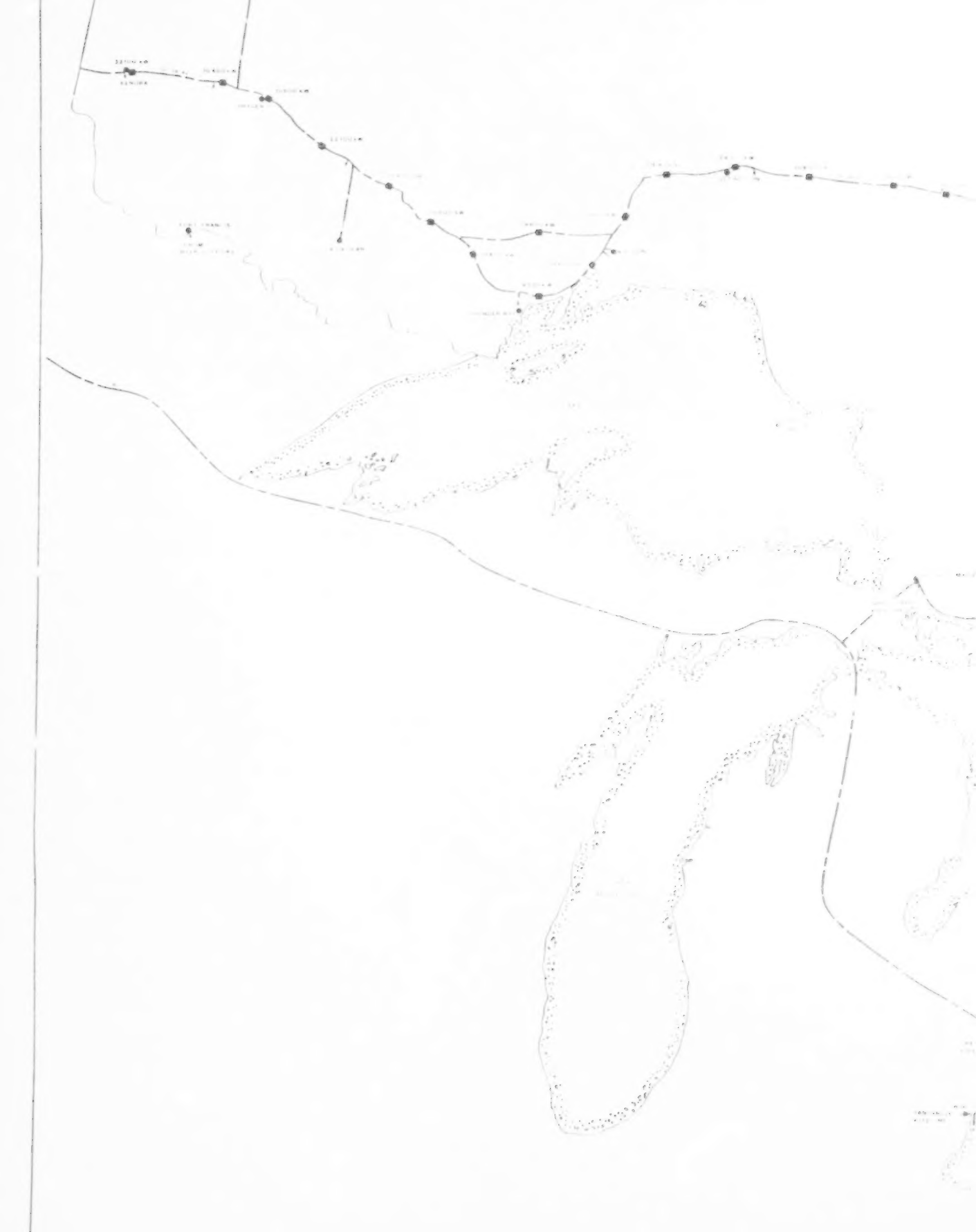
ESTIMATED TRANSPORTATION SERVICES
YEARS COMMENCING NOVEMBER 1, 1993 TO 1999

($10^6 m^3$ at 101.325 kPa)

LINE		Port of Exit	Licence	Class of Service	1993	1994	1995	1996	1997	1998	1999
	Canadian										
1	Saskatchewan Power Corporation			TS	770	770	770	770	770	770	770
2	Plains-Western (Manitoba) Ltd.			TS	85	85	85	85	85	85	85
3	Northern & Central Gas Corporation Ltd.			STS	99	99	99	99	99	99	99
4	Kingston Public Utilities Commission			STS	7	7	7	7	7	7	7
5	Gaz Inter-Cite Quebec			TS	350	350	350	350	350	350	350
6	Gaz Metropolitain, Inc.			TS	367	367	367	367	367	367	367
7				STS	170	170	170	170	170	170	170
8	Gaz Metropolitain, Inc.			Total	537	537	537	537	537	537	537
9	TransQuebec & Maritimes Pipeline			TS	220	220	220	220	220	220	220
10	TOTAL CANADIAN				2 068	2 068	2 068	2 068	2 068	2 068	2 068
	Existing Exports										
11	Consolidated Natural Gas Limited			TS	-	-	-	-	-	-	-
12	Proges Limited			TS	-	-	-	-	-	-	-
13	Sulpetro Limited			TS	-	-	-	-	-	-	-
14	TOTAL EXISTING EXPORTS				-	-	-	-	-	-	-
	New Exports										
15	ProGas Limited	Emerson	GL-81	TS	-	-	-	-	-	-	-
16	ProGas Limited	Niagara	GL-80	TS	518	518	518	389	260	129	-
17	Canadian-Montana Pipe Line Company	Niagara	GL-5,17,25,70,71	TS	378	218	119	-	-	-	-
18	Pan Alberta Gas Limited	Niagara	GL-95	TS	1 581	1 581	1 581	1 186	791	395	-
19	KennGaz Producers Limited	Niagara	GL-77	TS	1 292	1 292	1 292	969	646	323	-
20	Transcontinental Gas Pipe Line Corp.	Niagara	GL-91	STS	566	566	425	283	142	-	-
21	TOTAL NEW EXPORTS				4 335	4 175	3 935	2 827	1 839	847	-
22	TOTAL EXPORT TRANSPORTATION				4 335	4 175	3 935	2 827	1 839	847	-
23	TOTAL TRANSPORTATION				6 403	6 243	6 003	4 895	3 907	2 915	2 068
	SUMMARY - Class of Service										
24	Transportation Service			TS	5 561	5 401	5 302	4 356	3 489	2 639	1 792
25	Storage Transportation Service			STS	842	842	701	559	418	276	276
26	TOTAL TRANSPORTATION (Line 23)			Total	6 403	6 243	6 003	4 895	3 907	2 915	2 068

nenco

LEGEND
TRANSCANADA PIPELINES
GREAT LAKES PIPELINE
UNION GAS
CONSUMERS GAS



ONTARIO MINISTRY OF ENERGY

GAS TRANSMISSION AND STORAGE FACILITIES IN ONTARIO

JUNE 1986